CHESAPEAKE UTILITIES CORP
Form 10-Q
August 03, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended: June 30, 2017
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number: 001-11590

CHESAPEAKE UTILITIES CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	51-0064146
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

909 Silver Lake Boulevard, Dover, Delaware 19904
(Address of principal executive offices, including Zip Code)
(302) 734-6799
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15 (d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer ¨

Non-accelerated filer ¨ Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

Common Stock, par value $0.4867 — 16,344,442 shares outstanding as of July 31, 2017.

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GLOSSARY OF DEFINITIONS

ASC: Accounting Standards Codification
ASU: Accounting Standards Update
Aspire Energy: Aspire Energy of Ohio, LLC, a wholly-owned subsidiary of Chesapeake Utilities
CDD: Cooling degree-day, which is a measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is above 65 degrees Fahrenheit
Chesapeake or Chesapeake Utilities: Chesapeake Utilities Corporation, and its direct and indirect subsidiaries, as appropriate in the context of the disclosure
Chesapeake Pension Plan: A defined benefit pension plan sponsored by Chesapeake Utilities
Chesapeake Postretirement Plan: An unfunded postretirement health care and life insurance plan sponsored by Chesapeake Utilities
Chesapeake SERP: An unfunded supplemental executive retirement pension plan sponsored by Chesapeake Utilities
CIAC: Contributions from customers that are used to construct facilities
CGC: Consumer Gas Cooperative, an Ohio natural gas cooperative
CHP: Combined heat and power plant
Columbia Gas: Columbia Gas of Ohio, an unaffiliated local distribution company based in Ohio
Company: Chesapeake Utilities Corporation, and its direct and indirect subsidiaries, as appropriate in the context of the disclosure
Credit Agreement: The Credit Agreement dated October 8, 2015, among Chesapeake Utilities and the Lenders related to the Revolver
Deferred Compensation Plan: A non-qualified, deferred compensation arrangement under which certain of our executives and members of the Board of Directors are able to defer payment of all or a part of certain specified types of compensation, including executive cash bonuses, executive performance shares, and directors' retainers
Degree-Day: A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature (from 10:00 am to 10:00 am) falls above or below 65 degrees Fahrenheit
Delaware Division: Chesapeake Utilities' natural gas distribution operation serving customers in Delaware
Delmarva Peninsula: A peninsula on the east coast of the United States of America occupied by Delaware and portions of Maryland and Virginia
DNREC: Delaware Department of Natural Resources and Environmental Control
Dts/d: Dekatherms per day
Eastern Shore: Eastern Shore Natural Gas Company, a wholly-owned natural gas transmission subsidiary of Chesapeake Utilities
EGWIC: Eastern Gas & Water Investment Company, LLC, an affiliate of ESG
Eight Flags: Eight Flags Energy, LLC, a subsidiary of Chesapeake OnSight Services, LLC, which owns and operates a CHP plant on Amelia Island, Florida
EPA: United States Environmental Protection Agency
ESG: Eastern Shore Gas Company and its affiliates
FASB: Financial Accounting Standards Board

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FERC: Federal Energy Regulatory Commission, an independent agency of the United States government that regulates the interstate transmission of electricity, natural gas, and oil
FDEP: Florida Department of Environmental Protection
FGT: Florida Gas Transmission Company
Flo-gas: Flo-gas Corporation, a wholly-owned subsidiary of FPU
FPU: Florida Public Utilities Company, a wholly-owned subsidiary of Chesapeake Utilities
FPU Medical Plan: A separate unfunded postretirement medical plan for FPU sponsored by Chesapeake Utilities
FPU Pension Plan: A separate defined benefit pension plan for FPU sponsored by Chesapeake Utilities
GAAP: Accounting principles generally accepted in the United States of America
Gatherco: Gatherco, Inc., a corporation that merged with and into Aspire Energy on April 1, 2015
GRIP: The Gas Reliability Infrastructure Program, a natural gas pipeline replacement program in Florida pursuant to which we collect a surcharge from certain of our customers to recover capital and other program-related costs associated with the replacement of qualifying distribution mains and services
Gulf Power: Gulf Power Company, an unaffiliated electric company that supplies electricity to FPU
Gulfstream: Gulfstream Natural Gas System, LLC, an unaffiliated pipeline network that supplies natural gas to FPU
HDD: Heating degree-day, which is a measure of the variation in weather based on the extent to which the daily average temperature (from 10:00 am to 10:00 am) is below 65 degrees Fahrenheit
JEA: The unaffiliated community-owned utility located in Jacksonville, Florida, formerly known as Jacksonville Electric Authority
Lenders: PNC, Bank of America N.A., Citizens Bank N.A., Royal Bank of Canada, and Wells Fargo Bank, National Association, which are collectively the lenders that entered into the Credit Agreement with Chesapeake Utilities
MDE: Maryland Department of Environment
MetLife: MetLife Investment Advisors, an institutional debt investment management firm, with which we entered into the MetLife Shelf Agreement
MetLife Shelf Agreement: An agreement entered into by Chesapeake Utilities and MetLife in March 2017 pursuant to which Chesapeake Utilities may request that MetLife purchase, through March 2, 2020, up to $150 million of unsecured senior debt at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance
MGP: Manufactured gas plant, which is a site where coal was previously used to manufacture gaseous fuel for industrial, commercial and residential use
MWH: Megawatt hour, which is a unit of measurement for electricity
NYL: New York Life Investors LLC, an institutional debt investment management firm, with which we entered into the NYL Shelf Agreement
NYL Shelf Agreement: An agreement entered into by Chesapeake Utilities and NYL in March 2017 pursuant to which Chesapeake Utilities may request that NYL purchase, through March 2, 2020, up to $100 million of unsecured senior debt at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance
OPT ≤ 90 Service: Off Peak ≤ 90 Firm Transportation Service, a tariff associated with Eastern Shore's firm transportation service that enables Eastern Shore to forgo scheduling service for up to 90 days during the peak months of November through April each year
OTC: Over-the-counter
Peninsula Pipeline: Peninsula Pipeline Company, Inc., Chesapeake Utilities' wholly-owned Florida intrastate pipeline subsidiary
PESCO: Peninsula Energy Services Company, Inc., Chesapeake Utilities' wholly-owned natural gas marketing subsidiary

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PNC: PNC Bank, National Association, the administrative agent and primary lender for our Revolver
Prudential: Prudential Investment Management Inc., an institutional investment management firm, with which we have entered into the Prudential Shelf Agreement
Prudential Shelf Agreement: An agreement entered into by Chesapeake Utilities and Prudential pursuant to which Chesapeake Utilities may request that Prudential purchase, through October 7, 2018, up to $150.0 million of Prudential Shelf Notes at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance
Prudential Shelf Notes: Unsecured senior promissory notes that we may request Prudential to purchase under the Prudential Shelf Agreement
PSC: Public Service Commission, which is the state agency that regulates the rates and services provided by Chesapeake Utilities’ natural gas and electric distribution operations in Delaware, Maryland and Florida and Peninsula Pipeline in Florida
RAP: Remedial Action Plan, which is a plan that outlines the procedures taken or being considered in removing contaminants from a MGP formerly owned by Chesapeake Utilities or FPU
Rayonier: Rayonier Performance Fibers, LLC, the company that owns the property on which Eight Flags' CHP plant is located and that supplies electricity to FPU
Retirement Savings Plan: Chesapeake Utilities' qualified 401(k) retirement savings plan
Revolver: Our unsecured revolving credit facility with the Lenders
Rights Plan: A plan designed to protect against abusive or coercive takeover attempts or tactics that are contrary to the best interests of Chesapeake Utilities' stockholders
Sandpiper: Sandpiper Energy, Inc., Chesapeake Utilities' wholly-owned subsidiary, which provides a tariff-based distribution service to customers in Worcester County, Maryland
Sanford Group: FPU and other responsible parties involved with the Sanford MGP site
SEC: Securities and Exchange Commission
Senior Notes: Our unsecured long-term debt issued primarily to insurance companies on various dates
Sharp: Sharp Energy, Inc., Chesapeake Utilities' wholly-owned propane distribution subsidiary
SICP: 2013 Stock and Incentive Compensation Plan
TETLP: Texas Eastern Transmission, LP, an interstate pipeline interconnected with Eastern Shore's pipeline
Xeron: Xeron, Inc., an inactive subsidiary of Chesapeake Utilities, which previously engaged in propane and crude oil trading

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PART I—FINANCIAL INFORMATION
Item 1. Financial Statements
Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Income (Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
(in thousands, except shares and per share data)				
Operating Revenues				
Regulated Energy	$70,996	$ 67,395	$168,650	$156,611
Unregulated Energy and other	54,088	34,947	141,594	92,027
Total Operating Revenues	125,084	102,342	310,244	248,638
Operating Expenses				
Regulated Energy cost of sales	24,167	21,635	64,411	56,540
Unregulated Energy and other cost of sales	40,505	22,934	101,260	56,958
Operations	30,408	28,087	63,321	55,246
Maintenance	3,403	2,904	6,634	5,383
Gain from a settlement	(130)	(130)	(130)	(130)
Depreciation and amortization	9,094	7,780	17,906	15,283
Other taxes	3,971	3,390	8,501	7,236
Total Operating Expenses	111,418	86,600	261,903	196,516
Operating Income	13,666	15,742	48,341	52,122
Other expense, net	(607)	(8)	(884)	(42)
Interest charges	3,073	2,624	5,811	5,274
Income Before Income Taxes	9,986	13,110	41,646	46,806
Income taxes	3,940	5,081	16,456	18,410
Net Income	$6,046	$ 8,029	$25,190	$28,396
Weighted Average Common Shares Outstanding:				
Basic	16,340,665	15,315,020	16,329,009	15,300,931
Diluted	16,382,207	15,352,702	16,373,038	15,342,287
Earnings Per Share of Common Stock:				
Basic	$0.37	$ 0.52	$1.54	$1.86
Diluted	$0.37	$ 0.52	$1.54	$1.85
Cash Dividends Declared Per Share of Common Stock	$0.3250	$ 0.3050	$0.6300	$0.5925

The accompanying notes are an integral part of these financial statements.

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Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Comprehensive Income (Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
(in thousands)				
Net Income	$6,046	$8,029	$25,190	$28,396
Other Comprehensive (Loss) Income, net of tax:				
Employee Benefits, net of tax:				
Amortization of prior service cost, net of tax of $(8), $(8), $(16) and $(16), respectively	(12)	(12)	(23)	(24)
Net gain, net of tax of $69, $67, $145 and $133, respectively	101	99	194	200
Cash Flow Hedges, net of tax:				
Unrealized (loss)/gain on commodity contract cash flow hedges, net of tax of $(554), $313, $(362) and $322, respectively	(875)	496	(537)	496
Total Other Comprehensive (Loss) Income	(786)	583	(366)	672
Comprehensive Income	$5,260	$8,612	$24,824	$29,068

The accompanying notes are an integral part of these financial statements.

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Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)

Assets	June 30, 2017	December 31, 2016
(in thousands, except shares and per share data)		
Property, Plant and Equipment		
Regulated Energy	$ 1,038,929	$ 957,681
Unregulated Energy	202,707	196,800
Other businesses and eliminations	25,623	21,114
Total property, plant and equipment	1,267,259	1,175,595
Less: Accumulated depreciation and amortization	(260,428)	(245,207)
Plus: Construction work in progress	44,556	56,276
Net property, plant and equipment	1,051,387	986,664
Current Assets		
Cash and cash equivalents	2,419	4,178
Accounts receivable (less allowance for uncollectible accounts of $862 and $909, respectively)	41,113	62,803
Accrued revenue	11,812	16,986
Propane inventory, at average cost	4,649	6,457
Other inventory, at average cost	9,996	4,576
Regulatory assets	7,167	7,694
Storage gas prepayments	4,415	5,484
Income taxes receivable	14,409	22,888
Prepaid expenses	3,939	6,792
Mark-to-market energy assets	229	823
Other current assets	2,287	2,470
Total current assets	102,435	141,151
Deferred Charges and Other Assets		
Goodwill	15,070	15,070
Other intangible assets, net	1,664	1,843
Investments, at fair value	5,952	4,902
Regulatory assets	76,128	76,803
Receivables and other deferred charges	4,352	2,786
Total deferred charges and other assets	103,166	101,404
Total Assets	$ 1,256,988	$ 1,229,219

The accompanying notes are an integral part of these financial statements.

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Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Balance Sheets (Unaudited)

Capitalization and Liabilities	June 30, 2017	December 31, 2016
(in thousands, except shares and per share data)		
Capitalization		
Stockholders' equity		
Preferred stock, par value $0.01 per share (authorized 2,000,000 shares), no shares issued and outstanding	$—	$—
Common stock, par value $0.4867 per share (authorized 25,000,000 shares)	7,955	7,935
Additional paid-in capital	252,071	250,967
Retained earnings	206,896	192,062
Accumulated other comprehensive loss	(5,244)	(4,878)
Deferred compensation obligation	3,336	2,416
Treasury stock	(3,336)	(2,416)
Total stockholders' equity	461,678	446,086
Long-term debt, net of current maturities	201,590	136,954
Total capitalization	663,268	583,040
Current Liabilities		
Current portion of long-term debt	12,124	12,099
Short-term borrowing	145,591	209,871
Accounts payable	52,101	56,935
Customer deposits and refunds	30,725	29,238
Accrued interest	1,637	1,312
Dividends payable	5,312	4,973
Accrued compensation	6,683	10,496
Regulatory liabilities	5,609	1,291
Mark-to-market energy liabilities	188	773
Other accrued liabilities	12,084	7,063
Total current liabilities	272,054	334,051
Deferred Credits and Other Liabilities		
Deferred income taxes	234,716	222,894
Regulatory liabilities	42,427	43,064
Environmental liabilities	8,457	8,592
Other pension and benefit costs	31,920	32,828
Deferred investment tax credits and other liabilities	4,146	4,750
Total deferred credits and other liabilities	321,666	312,128
Environmental and other commitments and contingencies (Note 4 and 5)		
Total Capitalization and Liabilities	$ 1,256,988	$ 1,229,219

The accompanying notes are an integral part of these financial statements.

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Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Cash Flows (Unaudited)

	Six Months Ended June 30,	
	2017	2016
(in thousands)		
Operating Activities		
Net income	$25,190	$28,396
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	17,906	15,283
Depreciation and accretion included in other costs	3,939	3,436
Deferred income taxes	12,034	6,162
Realized loss on commodity contracts/sale of assets/investments	2,223	664
Unrealized loss/(gain) on investments/commodity contracts	184	(42)
Employee benefits and compensation	819	760
Share-based compensation	812	1,264
Other, net	(17)	24
Changes in assets and liabilities:		
Accounts receivable and accrued revenue	26,862	2,264
Propane inventory, storage gas and other inventory	(2,543)	663
Regulatory assets/liabilities, net	4,255	519
Prepaid expenses and other current assets	2,129	2,878
Accounts payable and other accrued liabilities	(280)	(561)
Income taxes receivable	8,500	20,680
Customer deposits and refunds	1,487	399
Accrued compensation	(3,876)	(3,340)
Other assets and liabilities, net	(3,254)	(1,786)
Net cash provided by operating activities	96,370	77,663
Investing Activities		
Property, plant and equipment expenditures	(88,627)	(72,783)
Proceeds from sales of assets	185	89
Environmental expenditures	(135)	(177)
Net cash used in investing activities	(88,577)	(72,871)
Financing Activities		
Common stock dividends	(9,636)	(8,453)
Issuance of stock for Dividend Reinvestment Plan	421	429
Tax withholding payments related to net settled stock compensation	(692)	(770)
Change in cash overdrafts due to outstanding checks	(2,370)	1,473
Net (repayment) borrowing under line of credit agreements	(61,910)	5,166
Proceeds from issuance of long-term debt	69,800	—
Repayment of long-term debt and capital lease obligation	(5,165)	(2,226)
Net cash used by financing activities	(9,552)	(4,381)
Net (Decrease) Increase in Cash and Cash Equivalents	(1,759)	411
Cash and Cash Equivalents—Beginning of Period	4,178	2,855
Cash and Cash Equivalents—End of Period	$2,419	$3,266

The accompanying notes are an integral part of these financial statements.

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Chesapeake Utilities Corporation and Subsidiaries
Condensed Consolidated Statements of Stockholders' Equity (Unaudited)

	Common Stock [1]							
(in thousands, except shares and per share data)	Number of Shares[2]	Par Value	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Deferred Compensation	Treasury Stock	Total [2]
Balance at December 31, 2015	15,270,659	$7,432	$190,311	$166,235	$ (5,840)	$ 1,883	$(1,883)	$358,138
Net income	—	—	—	44,675	—	—	—	44,675
Other comprehensive income	—	—	—	—	962	—	—	962
Dividend declared ($1.2025 per share)	—	—	—	(18,848)	—	—	—	(18,848)
Retirement savings plan and dividend reinvestment plan	36,253	17	2,225	—	—	—	—	2,242
Stock issuance [3]	960,488	467	56,893	—	—	—	—	57,360
Share-based compensation and tax benefit [4] [5]	36,099	19	1,538	—	—	—	—	1,557
Treasury stock activities	—	—	—	—	—	533	(533)	—
Balance at December 31, 2016	16,303,499	7,935	250,967	192,062	(4,878)	2,416	(2,416)	446,086
Net income	—	—	—	25,190	—	—	—	25,190
Other comprehensive loss	—	—	—	—	(366)	—	—	(366)
Dividend declared ($0.6300 per share)	—	—	—	(10,356)	—	—	—	(10,356)
Dividend reinvestment plan	10,771	5	731	—	—	—	—	736
Share-based compensation and tax benefit [4] [5]	30,172	15	373	—	—	—	—	388
Treasury stock activities	—	—	—	—	—	920	(920)	—
Balance at June 30, 2017	16,344,442	$7,955	$252,071	$206,896	$ (5,244)	$ 3,336	$(3,336)	$461,678

(1) 2,000,000 shares of preferred stock at $0.01 par value has been authorized. None has been issued or is outstanding; accordingly, no information has been included in the statements of stockholders' equity.

(2) Includes 90,201 and 76,745 shares at June 30, 2017 and December 31, 2016, respectively, held in a Rabbi Trust related to our Deferred Compensation Plan.

(3) On September 22, 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million.

(4) Includes amounts for shares issued for Directors' compensation.

(5) The shares issued under the SICP are net of shares withheld for employee taxes. For the six months ended June 30, 2017, and for the year ended December 31, 2016, we withheld 10,269 and 12,031 shares, respectively, for taxes.

The accompanying notes are an integral part of these financial statements.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. Summary of Accounting Policies

Basis of Presentation

References in this document to the “Company,” “Chesapeake Utilities,” “we,” “us” and “our” are intended to mean Chesapeake Utilities Corporation, its divisions and/or its subsidiaries, as appropriate in the context of the disclosure.

The accompanying unaudited condensed consolidated financial statements have been prepared in compliance with the rules and regulations of the SEC and GAAP. In accordance with these rules and regulations, certain information and disclosures normally required for audited financial statements have been condensed or omitted. These financial statements should be read in conjunction with the consolidated financial statements and notes thereto, included in our latest Annual Report on Form 10-K for the year ended December 31, 2016. In the opinion of management, these financial statements reflect normal recurring adjustments that are necessary for a fair presentation of our results of operations, financial position and cash flows for the interim periods presented.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is highest due to colder temperatures.

We reclassified certain amounts in the condensed consolidated statement of cash flows for the six months ended June 30, 2016 to conform to the current year’s presentation. These reclassifications are considered immaterial to the overall presentation of our condensed consolidated financial statements.

Subsequent Event

On June 20, 2017, PESCO entered into an agreement to purchase certain operating assets of ARM Energy Management. These assets are used to provide natural gas supply and supply management services to commercial and industrial customers in Western Pennsylvania. The transaction was consummated on August 1, 2017 and will not have a material impact on our financial results.

FASB Statements and Other Authoritative Pronouncements

Recently Adopted Accounting Standards

Inventory (ASC 330) - In July 2015, the FASB issued ASU 2015-11, Simplifying the Measurement of Inventory. Under this guidance, inventories are required to be measured at the lower of cost or net realizable value. Net realizable value represents the estimated selling price less costs associated with completion, disposal and transportation. We adopted ASU 2015-11 on January 1, 2017 on a prospective basis. Adoption of this standard did not have a material impact on our financial position or results of operations.

Recent Accounting Standards Yet to be Adopted

Revenue from Contracts with Customers (ASC 606) - In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. This standard provides a single comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, as well as across industries and capital markets. The standard contains principles that entities will apply to determine the measurement of revenue and when it is recognized. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. In March 2016, FASB issued ASU 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), to clarify the implementation guidance on principal versus agent considerations. For public entities, this standard is effective for interim and annual financial statements issued beginning January 1, 2018. We are in the process of evaluating our revenue sources and assessing the impact on our financial position, results of operations and cash flows. We expect this evaluation to be completed in the third quarter of 2017. In tandem, we have developed and documented accounting policies and position papers, which are intended to meet the requirements of this new revenue recognition standard. We have also completed our plan to update our internal controls and make the necessary system and process changes. In the third quarter of 2017, we will provide additional training to our employees and implement system and process changes that are associated with the adoption of the standard. We plan to utilize the modified retrospective transition method upon adoption of this standard.

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Based on our current assessment, we believe that the implementation of this new standard will not have a material impact on the amount and timing of revenue recognition except for one long-term contract for which we will delay the recognition of revenue of approximately $407,000 in 2018. Since we have not yet finalized our assessment, we will continue to monitor and subsequently disclose future identified material impacts, if any, in our quarterly report on Form 10-Q for the third quarter of 2017. In addition, the AICPA Power and Utilities Industry Task Force is addressing issues specific to our industry, including CIAC, and has concluded that CIAC is outside of the scope of this standard; accordingly, our Regulated Energy segment accounting for CIAC will not change as a result of ASC 606.

Leases (ASC 842) - In February 2016, the FASB issued ASU 2016-02, Leases, which provides updated guidance regarding accounting for leases. This update requires a lessee to recognize a lease liability and a lease asset for all leases, including operating leases, with a term greater than 12 months on its balance sheet. The update also expands the required quantitative and qualitative disclosures surrounding leases. ASU 2016-02 will be effective for our annual and interim financial statements beginning January 1, 2019, although early adoption is permitted.

We have assessed all of our leases and have concluded that a majority of our operating leases would continue to fall within the category of operating leases; however, we may have some leases that qualify for the short-term lease exception. We will record the right to use of assets and the lease liability related to the operating leases, but we do not believe that this will have a material impact on our financial position, results of operations and cash flows. During the third and fourth quarters of 2017, we intend to quantify the overall impact that may result from early adoption of the standard and implementation of the overall process. This guidance will be applied using the modified retrospective transition method for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

Statement of Cash Flows (ASC 230) - In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments, which clarifies how certain transactions are classified in the statement of cash flows. ASU 2016-15 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. We are assessing the impact of the adoption of this ASU on our statements of cash flows.

Intangibles-Goodwill (ASC 350) - In January 2017, the FASB issued ASU 2017-04, Simplifying the Test for Goodwill Impairment, which simplifies how an entity is required to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. ASU 2017-04 will be effective for our annual and interim financial statements beginning January 1, 2020, although early adoption is permitted. The amendments included in this ASU are to be applied prospectively. We are evaluating the effect of this ASU on our future financial position and results of operations.

Compensation-Retirement Benefits (ASC 715) - In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Post Retirement Benefit Cost. Under this guidance, employers are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by the pertinent employees during the period. The other components of net benefit costs are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The update allows for capitalization of the service cost component when applicable. ASU 2017-07 will be effective for our annual and interim financial statements beginning January 1, 2018, although early adoption is permitted. The presentation of the service cost and other components in this update are to be applied retrospectively and the capitalization of the service cost is to be applied prospectively on or after the effective date. We are evaluating the effect of this update on our future financial position and results of operations.

Compensation - Stock Compensation (ASC 718) - In May 2017, the FASB issued ASU 2017-09, Scope of Modification Accounting, to clarify when to account for a change in the terms or conditions of a share-based payment award as a modification. Under this guidance, modification accounting is required only if the fair value, the vesting conditions or the award classification (equity or liability) changes as a result of a change in the terms or conditions of the award. The guidance is effective for our annual financial statements beginning January 1, 2018, although early adoption is permitted. The amendments included in this standard are to be applied prospectively. We are evaluating the effect of this update on our future financial position and results of operations.

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2. Calculation of Earnings Per Share

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
(in thousands, except shares and per share data)				
Calculation of Basic Earnings Per Share:				
Net Income	$6,046	$ 8,029	$25,190	$ 28,396
Weighted average shares outstanding	16,340,665	15,315,020	16,329,009	15,300,931
Basic Earnings Per Share	$0.37	$ 0.52	$1.54	$ 1.86
Calculation of Diluted Earnings Per Share:				
Reconciliation of Numerator:				
Net Income	$6,046	$ 8,029	25,190	28,396
Reconciliation of Denominator:				
Weighted shares outstanding—Basic	16,340,665	15,315,020	16,329,009	15,300,931
Effect of dilutive securities—Share-based compensation	41,542	37,682	44,029	41,356
Adjusted denominator—Diluted	16,382,207	15,352,702	16,373,038	15,342,287
Diluted Earnings Per Share	$0.37	$ 0.52	$1.54	$ 1.85

3. Rates and Other Regulatory Activities

Our natural gas and electric distribution operations in Delaware, Maryland and Florida are subject to regulation by their respective PSC; Eastern Shore, our natural gas transmission subsidiary, is subject to regulation by the FERC; and Peninsula Pipeline, our intrastate pipeline subsidiary, is subject to regulation by the Florida PSC. Chesapeake Utilities' Florida natural gas distribution division and FPU’s natural gas and electric distribution operations continue to be subject to regulation by the Florida PSC as separate entities.

Delaware

Rate Case Filing: In December 2015, our Delaware Division filed an application with the Delaware PSC for a base rate increase and certain other changes to its tariff. The Delaware Division, Delaware PSC Staff, the Division of the Public Advocate and other intervenors met and reached a settlement agreement in November 2016. The terms of the settlement agreement included an annual increase of $2.25 million in base rates. The order became final in December 2016, and the new rates became effective January 1, 2017. Amounts collected through interim rates in excess of the respective portion of the $2.25 million increase through December 31, 2016 were accrued as of that date. In January 2017, we filed our proposed refund plan with the Delaware PSC and subsequently issued refunds to customers in March 2017.

Florida

Cost Recovery for the Electric Interconnect Project: In September 2015, FPU’s electric division filed to recover the cost of the proposed Florida Power & Light Company interconnect project through FPU's annual Fuel and Purchased Power Cost Recovery Clause filing. The interconnect project would enable FPU's electric division to negotiate a new power purchase agreement to mitigate fuel costs for its Northeast division. FPU's proposal was approved by the Florida PSC at its Agenda Conference held in December 2015. In January 2016, however, the Office of Public Counsel filed an appeal of the Florida PSC's decision with the Florida Supreme Court. The Florida Supreme Court reversed the Florida PSC decision in March 2017, after consideration of the parties' legal briefs and oral arguments. As a result, FPU will exclude the recovery of these costs from its 2018 Fuel and Purchased Power Cost Recovery Clause filing and plans to include this project for recovery in a limited proceeding.

Surcharge Associated with Modernization of Electric Distribution System Project: In February 2017, FPU’s electric division filed a petition with the Florida PSC requesting a temporary surcharge mechanism to recover costs and generate an appropriate return on investment associated with an essential reliability and modernization project for its electric distribution system ("Modernization of Electric Distribution System Project"). We requested approval to invest approximately $59.8 million over a five-year period associated with the Modernization of Electric Distribution System

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Project. In February 2017, the Office of Public Counsel intervened in this petition. The Florida PSC requested that FPU file a limited proceeding to include these investments in base rates instead of seeking approval of a temporary surcharge. In April 2017, FPU voluntarily withdrew its petition and subsequently filed the limited proceeding described in the next paragraph.

Electric Limited Proceeding: In July 2017, FPU's electric division filed a petition with the Florida PSC requesting inclusion of certain capital projects in its rate base, and to adjust its base rates accordingly. These projects are designed to significantly improve the stability and outage response times for FPU's electric distribution system and potentially enable it to mitigate fuel costs for its electric customers through the Florida Power & Light Company interconnect project.

Eastern Shore

White Oak Mainline Expansion Project: In November 2014, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate certain expansion facilities designed to provide 45,000 Dts/d of firm transportation service to an electric power generator in Kent County, Delaware ("White Oak Mainline Project"). Eastern Shore proposed to construct approximately 7.2 miles of 16-inch diameter pipeline looping in Chester County, Pennsylvania and increase compression capability at Eastern Shore's existing Delaware City compressor station in New Castle County, Delaware. In November 2015, Eastern Shore filed an amendment to this application, which indicated the preferred pipeline route and shortened the total miles of the proposed pipeline to 5.4 miles.

In July 2016, the FERC authorized Eastern Shore to construct and operate the proposed White Oak Mainline Project. As of the end of March 2017, the entire project was placed into service. The total cost to complete the project was approximately $41.0 million.

System Reliability Project: In May 2015, Eastern Shore submitted an application to the FERC seeking authorization to construct, own and operate approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware, and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. Eastern Shore further proposed to reinforce critical points on its pipeline system. Eastern Shore requested a predetermination of rolled-in rate treatment for the costs of the project. In July 2016, the FERC granted Eastern Shore's pre-determination of rolled-in rate treatment absent any significant change in circumstances.

In September 2016, the FERC granted approval to start construction on all phases of the project. As of June 2017, the entire project was placed into service. The cost of the project was approximately $38.0 million. We will begin to recover the project's costs in August 2017, coinciding with the proposed effectiveness of new rates, subject to refund pending final resolution of the base rate case.

2017 Expansion Project: In May 2016, Eastern Shore submitted a request to the FERC to initiate the pre-filing review procedures for Eastern Shore's 2017 expansion project (the “2017 Expansion Project”). The 2017 Expansion Project's facilities include approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; upgrades to existing metering facilities in Lancaster County, Pennsylvania; installation of an additional compressor unit at Eastern Shore's existing Daleville compressor station in Chester County, Pennsylvania; and approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. In May 2016, the FERC approved Eastern Shore's request to commence the pre-filing review process. Eastern Shore entered into Precedent Agreements with seven existing customers, including three affiliates of Chesapeake Utilities, for a total of 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities.

In December 2016, Eastern Shore submitted an application for a certificate of public convenience and necessity seeking authorization to construct the expansion facilities. Six of Eastern Shore's existing customers timely intervened to become parties. In February 2017, Eastern Shore submitted responses to the FERC staff's data requests.

In May 2017, the FERC staff issued the environmental assessment and set forth 22 environmental conditions with which Eastern Shore must comply. The FERC provided a 30-day comment period, which expired in June 2017. Comments were timely submitted by four relevant state and federal agencies and two private parties. Eastern Shore submitted responses to all comments.

In June 2017 and July 2017, the FERC issued requests for additional information related to a wetland area at the Jennersville Loop in Chester County, Pennsylvania. Eastern Shore submitted responses to both requests. The

estimated cost of the 2017 Expansion Project is approximately $98.6 million.
2017 Rate Case Filing: In January 2017, Eastern Shore filed a base rate proceeding with the FERC, as required by the terms of its 2012 rate case settlement agreement. Eastern Shore's proposed rates were based on the mainline cost of service of approximately $60.0 million resulting in an overall requested revenue increase of approximately $18.9 million and a requested rate of return on common equity of 13.75 percent. The filing includes incremental rates for the White Oak

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Mainline Expansion project, which benefits a single customer. Eastern Shore is also proposing to revise its depreciation rates and negative salvage rate based on the results of independent, third-party depreciation and negative salvage value studies. The FERC issued a notice of the filing in January 2017, and the comment period ended in February 2017. Fourteen parties intervened in the proceeding with six of those parties filing protests to various aspects of the filing. New rates were proposed to be effective on March 1, 2017; however, the FERC issued an order suspending the tariff rates for the usual five-month period. Eastern Shore has filed the requisite notice with the FERC to implement interim rates effective August 1, 2017.

Eastern Shore has participated in several settlement conferences, in which the FERC staff has reviewed its proposals, and customers and interested parties have presented and discussed their positions. Another settlement conference is scheduled for August 30 and 31, 2017.

4. Environmental Commitments and Contingencies

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remediate, at current and former operating sites, the effect on the environment of the disposal or release of specified substances.

MGP Sites

We have participated in the investigation, assessment or remediation of, and have exposures at, seven former MGP sites. Those sites are located in Salisbury, Maryland, Seaford, Delaware and Winter Haven, Key West, Pensacola, Sanford and West Palm Beach, Florida. We have also been discussing with the MDE another former MGP site located in Cambridge, Maryland.

As of June 30, 2017, we had approximately $9.8 million in environmental liabilities, related to FPU’s MGP sites in Florida, which include the Key West, Pensacola, Sanford and West Palm Beach sites. FPU has approval to recover, from insurance and from customers through rates, up to $14.0 million of its environmental costs related to its MGP sites. Approximately $10.8 million has been recovered as of June 30, 2017, leaving approximately $3.2 million in regulatory assets for future recovery of environmental costs from FPU’s customers.

Environmental liabilities for our MGP sites are recorded on an undiscounted basis based on the estimate of future costs provided by independent consultants. We continue to expect that all costs related to environmental remediation and related activities, including any potential future remediation costs for which we do not currently have approval for regulatory recovery, will be recoverable from customers through rates.

West Palm Beach, Florida

Remedial options are being evaluated to respond to environmental impacts to soil and groundwater at and in the immediate vicinity of a parcel of property owned by FPU in West Palm Beach, Florida, on which FPU previously operated a MGP. FPU is implementing a remedial plan approved by the FDEP for the east parcel of the site, which includes installation of monitoring test wells, sparging of air into the groundwater system and extraction of vapors from the subsurface. In January 2016, FDEP conducted a facility inspection and found no problems or deficiencies. We expect that similar remedial actions will ultimately be implemented for other portions of the site. Estimated costs of remediation for the West Palm Beach site range from approximately $4.5 million to $15.4 million, including costs associated with the relocation of FPU’s operations at this site, which is necessary to implement the remedial plan, and any potential costs associated with future redevelopment of the properties.

Sanford, Florida

FPU is the current owner of property in Sanford, Florida, which was a former MGP site that was operated by several other entities before FPU acquired the property. FPU was never an owner or an operator of the MGP at this site. In January 2007, FPU and the Sanford Group signed a Third Participation Agreement, which provides for the funding of the final remedy approved by the EPA for the site. FPU’s share of remediation costs under the Third Participation Agreement is set at five percent of a maximum of $13.0 million, or $650,000. As of June 30, 2017, FPU has paid $650,000 to the Sanford Group escrow account for its entire share of the funding requirements.

In December 2014, the EPA issued a preliminary close-out report, documenting the completion of all physical remedial construction activities at the Sanford site. Groundwater monitoring and statutory five-year reviews to ensure performance of the approved remedy will continue on this site. The total cost of the final remedy is estimated to be over $20.0 million, which includes long-term monitoring and the settlement of claims asserted by two adjacent property owners to resolve damages that the property owners allege they have incurred and will incur as a result of the implementation of the EPA-

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approved remediation. In settlement of these claims, members of the Sanford Group, which in this instance does not include FPU, have agreed to pay specified sums of money to the parties. FPU has refused to participate in the funding of the third-party settlement agreements based on its contention that it did not contribute to the release of hazardous substances at the site giving rise to the third-party claims. FPU has advised the other members of the Sanford Group that it is unwilling at this time to agree to pay any sum in excess of the $650,000 committed and paid by FPU in the Third Participation Agreement. The Sanford Group has not requested that FPU contribute to costs beyond the originally agreed upon $650,000 contribution.

As of June 30, 2017, FPU’s remaining remediation expenses, including attorneys’ fees and costs, are estimated to be $24,000. However, we are unable to determine to a reasonable degree of certainty whether the other members of the Sanford Group will accept FPU’s asserted defense to liability for costs exceeding $13.0 million to implement the final remedy for this site, as provided for in the Third Participation Agreement, or will pursue a claim against FPU for a sum in excess of the $650,000 that FPU has paid pursuant to the Third Participation Agreement. No such claims have been made as of June 30, 2017.

Winter Haven, Florida

The Winter Haven site is located on the eastern shoreline of Lake Shipp, in Winter Haven, Florida. Pursuant to a consent order entered into with FDEP, we are obligated to assess and remediate environmental impacts at this former MGP site. Groundwater monitoring results have shown a continuing reduction in contaminant concentrations from the sparging system, which has been in operation since 2002. In September 2014, FDEP issued a letter approving shutdown of the sparging operations on the northern portion of the site, contingent upon continued semi-annual monitoring.

Groundwater monitoring results from testing conducted in April 2017 indicated that natural attenuation default criteria were met at all but two wells, and were submitted in a letter report to FDEP in June 2017. FDEP issued a comment letter dated June 15, 2017 requesting additional delineation of the plume in the southwest corner. We plan to install an additional well at the southwest corner of the property and to continue monitoring groundwater quality while operating the bio-sparge system.

We estimate that future remediation costs for the subsurface soils and groundwater at the site should not exceed $425,000, which includes an estimate of $100,000 to implement additional actions, such as institutional controls, at the site.

FDEP previously indicated that we could also be required to remediate sediments along the shoreline of Lake Shipp, immediately west of the site. Based on studies performed to date, and our recent meeting with FDEP, we believe that corrective measures for lake sediments are not warranted and will not be required by FDEP; therefore, we have not recorded a liability for sediment remediation.

Seaford, Delaware

In December 2013, the DNREC notified us that it would be conducting a facility evaluation of a former MGP site in Seaford, Delaware. In a report issued in January 2015, DNREC provided the evaluation, which found several compounds within the groundwater and soil that required further investigation. In September 2015, DNREC approved our application to enter this site into the voluntary cleanup program. A remedial investigation was conducted in December 2015, which resulted in DNREC requesting additional investigative work be performed prior to approval of potential remedial actions. In December 2016, additional on-site wells were installed, developed and sampled pursuant to a September 2016 request from DNREC. The results of the sampling event and proposed future activities were submitted to DNREC in April 2017. We estimate the cost of potential remedial actions, based on the findings of the DNREC report, to be between $273,000 and $465,000.

Cambridge, Maryland

We are discussing with the MDE a former MGP site located in Cambridge, Maryland. The outcome of this matter cannot be determined at this time; therefore, we have not recorded an environmental liability for this location.

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5. Other Commitments and Contingencies

Natural Gas, Electric and Propane Supply

We have entered into contractual commitments to purchase natural gas, electricity and propane from various suppliers. The contracts have various expiration dates. In 2017, our Delmarva natural gas distribution operations entered into asset management agreements with PESCO to manage a portion of their natural gas transportation and storage capacity. The agreements were effective as of April 1, 2017, and each has a three-year term, expiring on March 31, 2020. Previously, the Delaware PSC approved PESCO to serve as an asset manager.

In May 2013, Sandpiper entered into a capacity, supply and operating agreement with EGWIC to purchase propane over a six-year term ending in May 2019. Sandpiper's current annual commitment is estimated at approximately 2.9 million gallons. Sandpiper has the option to enter into either a fixed per-gallon price for some or all of the propane purchases or a market-based price utilizing one of two local propane pricing indices.

Also in May 2013, Sharp entered into a separate supply and operating agreement with EGWIC. Under this agreement, Sharp has a commitment to supply propane to EGWIC over a six-year term ending in May 2019. Sharp's current annual commitment is estimated at approximately 2.9 million gallons. The agreement between Sharp and EGWIC is separate from the agreement between Sandpiper and EGWIC, and neither agreement permits the parties to set off the rights and obligations specified in one agreement against those specified in the other agreement.

Chesapeake Utilities' Florida natural gas distribution division has firm transportation service contracts with FGT and Gulfstream. Pursuant to a capacity release program approved by the Florida PSC, all of the capacity under these agreements has been released to various third parties, including PESCO. Under the terms of these capacity release agreements, Chesapeake Utilities is contingently liable to FGT and Gulfstream should any party that acquired the capacity through release fail to pay the capacity charge.

FPU’s electric fuel supply contracts require FPU to maintain an acceptable standard of creditworthiness based on specific financial ratios. FPU’s agreement with JEA requires FPU to comply with the following ratios based on the results of the prior 12 months: (a) total liabilities to tangible net worth less than 3.75 times and (b) a fixed charge coverage ratio greater than 1.5 times. If either ratio is not met by FPU, it has 30 days to cure the default or, provide an irrevocable letter of credit if the default is not cured. FPU’s electric fuel supply agreement with Gulf Power requires FPU to meet the following ratios based on the average of the prior six quarters: (a) funds from operations interest coverage ratio (minimum of 2 times) and (b) total debt to total capital (maximum of 65 percent). If FPU fails to meet the requirements, it has to provide the supplier a written explanation of actions taken, or proposed to be taken, to become compliant. Failure to comply with the ratios specified in the Gulf Power agreement could also result in FPU having to provide an irrevocable letter of credit. As of June 30, 2017, FPU was in compliance with all of the requirements of its fuel supply contracts.

Eight Flags provides electricity and steam generation services through its CHP plant located on Amelia Island, Florida. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. In July 2016, Eight Flags also started selling steam to Rayonier pursuant to a separate 20-year contract. The CHP plant is powered by natural gas transported by FPU through its distribution system and Peninsula Pipeline through its intrastate pipeline.

Corporate Guarantees

We have issued corporate guarantees to certain of our subsidiaries' vendors, the largest of which is PESCO. These corporate guarantees provide for the payment of propane and natural gas purchases in the event that PESCO defaults. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded when incurred. The aggregate amount guaranteed at June 30, 2017 was approximately $57.2 million, with the guarantees expiring on various dates through June 2018.

Chesapeake Utilities also guarantees the payment of FPU’s first mortgage bonds. The maximum exposure under this guarantee is the outstanding principal plus accrued interest balances. The outstanding principal balances of FPU’s first mortgage bonds approximate their carrying values (see Note 13, Long-Term Debt, for further details).

Letters of Credit

As of June 30, 2017, we have issued letters of credit totaling approximately $5.8 million related to the electric transmission services for FPU's electric division, the firm transportation service agreement between TETLP and our

Delaware and Maryland divisions, and to our current and previous primary insurance carriers. These letters of credit have various

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expiration dates through June 2018. There have been no draws on these letters of credit as of June 30, 2017. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that the letters of credit will be renewed to the extent necessary in the future.

Other

We are involved in certain other legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental agencies concerning rates. In the opinion of management, the ultimate disposition of these proceedings will not have a material effect on our consolidated financial position, results of operations or cash flows.

6. Segment Information

We use the management approach to identify operating segments. We organize our business around differences in regulatory environment and/or products or services, and the operating results of each segment are regularly reviewed by the chief operating decision maker (our Chief Executive Officer) in order to make decisions about resources and to assess performance. The segments are evaluated based on their pre-tax operating income. Our operations are comprised of two reportable segments:

- Regulated Energy. The Regulated Energy segment includes natural gas distribution, natural gas transmission and electric distribution operations. All operations in this segment are regulated, as to their rates and services, by the PSC having jurisdiction in each operating territory or by the FERC in the case of Eastern Shore.
- Unregulated Energy. The Unregulated Energy segment includes propane distribution as well as natural gas marketing, gathering, processing, transportation and supply. These operations are unregulated as to their rates and services. Effective June 2016, this segment includes electricity and steam generation through Eight Flags' CHP plant. Through March 31, 2017, this segment also included the operations of Xeron, our propane and crude oil trading subsidiary that began winding down operations at the end of the first quarter of 2017. Lastly, this segment also includes other unregulated energy services, such as energy-related merchandise sales and heating, ventilation and air conditioning, plumbing and electrical services.

Other operations are presented as “Other businesses and eliminations,” which consist of unregulated subsidiaries that own real estate leased to Chesapeake Utilities, as well as certain corporate costs not allocated to other operations.

Our operations are entirely domestic.

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The following table presents financial information about our reportable segments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
(in thousands)				
Operating Revenues, Unaffiliated Customers				
Regulated Energy segment	$68,815	$66,590	$165,261	$155,483
Unregulated Energy segment and other businesses	56,269	35,752	144,983	93,154
Total operating revenues, unaffiliated customers	$125,084	$102,342	$310,244	$248,637
Intersegment Revenues [1]				
Regulated Energy segment	$2,181	$805	$3,389	$1,128
Unregulated Energy segment	6,780	1,052	10,791	1,165
Other businesses	159	240	387	466
Total intersegment revenues	$9,120	$2,097	$14,567	$2,759
Operating Income				
Regulated Energy segment	$13,730	$15,226	$36,747	$39,545
Unregulated Energy segment	(38)	412	11,492	12,347
Other businesses and eliminations	(26)	104	102	230
Total operating income	13,666	15,742	48,341	52,122
Other expense, net	(607)	(8)	(884)	(42)
Interest	3,073	2,624	5,811	5,274
Income before Income Taxes	9,986	13,110	41,646	46,806
Income taxes	3,940	5,081	16,456	18,410
Net Income	$6,046	$8,029	$25,190	$28,396

(1) All significant intersegment revenues are billed at market rates and have been eliminated from consolidated operating revenues.

(in thousands)	June 30, 2017	December 31, 2016
Identifiable Assets		
Regulated Energy segment	$1,025,745	$986,752
Unregulated Energy segment	202,730	226,368
Other businesses and eliminations	28,513	16,099
Total identifiable assets	$1,256,988	$1,229,219

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7. Stockholder's Equity

Preferred Stock

We had 2,000,000 authorized and unissued shares of preferred stock, $0.01 par value per share, as of June 30, 2017 and December 31, 2016. Shares of preferred stock may be issued from time to time, by authorization of our Board of Directors and without the necessity of further action or authorization by stockholders, in one or more series and with such voting powers, designations, preferences and relative, participating, optional or other special rights and qualifications as the Board of Directors may, in its discretion, determine.

Common Stock Public Offering

In September 2016, we completed a public offering of 960,488 shares of our common stock at a public offering price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit.

Stockholders' Rights

Pursuant to authority granted under Delaware law and our Certificate of Incorporation, our Board of Directors previously declared a dividend of one preferred stock purchase right (each, a "Right," and, collectively, the "Rights") for each outstanding share of our common stock held of record on September 3, 1999, as adjusted for our stock split in September of 2014, and for additional shares of common stock issued since that time. The description and terms of the Rights are set forth in the Rights Plan. Unless exercised, the Rights trade with our common stock and are evidenced by the common stock certificate. In general, each Right will become exercisable and trade independently from our common stock upon a person or entity acquiring a beneficial ownership of 15 percent or more of our outstanding common stock.

Each Right, if it becomes exercisable, initially entitles the holder to purchase one fiftieth of a share of our Series A Participating Cumulative Preferred Stock, par value $0.01 per share, at a price of $70 per unit, subject to anti-dilution adjustments. Upon a person or entity becoming an "acquiring person," each Right (other than the Rights held by the acquiring person) will become exercisable to purchase a number of shares of our common stock having a market value equal to two times the exercise price of the Right. The Rights expire on August 20, 2019, unless they are redeemed earlier by us at the redemption price of $0.01 per Right. We may redeem the Rights at any time before they become exercisable and thereafter only in limited circumstances.

Accumulated Other Comprehensive (Loss)

Defined benefit pension and postretirement plan items, unrealized gains (losses) of our propane swap agreements, call options and natural gas futures contracts, designated as commodity contracts cash flow hedges, are the components of our accumulated comprehensive income (loss).

The following tables present the changes in the balance of accumulated other comprehensive loss for the six months ended June 30, 2017 and 2016. All amounts are presented net of tax.

(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2016	$ (5,360)	$ 482	$ (4,878)
Other comprehensive (loss)/income before reclassifications	(9)	837	828
Amounts reclassified from accumulated other comprehensive (loss)/income	180	(1,374)	(1,194)
Net current-period other comprehensive (loss)/income	171	(537)	(366)
As of June 30, 2017	$ (5,189)	$ (55)	$ (5,244)

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(in thousands)	Defined Benefit Pension and Postretirement Plan Items	Commodity Contracts Cash Flow Hedges	Total
As of December 31, 2015	$ (5,580)	$ (260)	$(5,840)
Other comprehensive income before reclassifications	—	525	525
Amounts reclassified from accumulated other comprehensive loss	176	(29)	147
Net prior-period other comprehensive income	176	496	672
As of June 30, 2016	$ (5,404)	$ 236	$(5,168)

The following table presents amounts reclassified out of accumulated other comprehensive loss for the three and six months ended June 30, 2017 and 2016. Deferred gains or losses for our commodity contracts cash flow hedges are recognized in earnings upon settlement.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	2017	2016	2017	2016
Amortization of defined benefit pension and postretirement plan items:				
Prior service credit [1]	$20	$20	$39	$40
Net loss[1]	(170)	(166)	(339)	(333)
Total before income taxes	(150)	(146)	(300)	(293)
Income tax benefit	61	58	120	117
Net of tax	$(89)	$(88)	$(180)	$(176)
Gains and losses on commodity contracts cash flow hedges				
Propane swap agreements [2]	$77	$—	$465	$(322)
Natural gas futures [2]	631	211	1,781	359
Total before income taxes	708	211	2,246	37
Income tax (expense) benefit	(273)	(81)	(872)	(8)
Net of tax	435	130	1,374	29
Total reclassifications for the period	$346	$42	$1,194	$(147)

[1] These amounts are included in the computation of net periodic costs (benefits). See Note 8, Employee Benefit Plans, for additional details.
[2] These amounts are included in the effects of gains and losses from derivative instruments. See Note 11, Derivative Instruments, for additional details.

Amortization of defined benefit pension and postretirement plan items is included in operations expense, and gains and losses on propane swap agreements and call options are included in cost of sales, in the accompanying condensed consolidated statements of income. The income tax benefit is included in income tax expense in the accompanying condensed consolidated statements of income.

8. Employee Benefit Plans

Net periodic benefit costs for our pension and post-retirement benefits plans for the three and six months ended June 30, 2017 and 2016 are set forth in the following tables:

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	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Three Months Ended June 30,	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016
(in thousands)										
Interest cost	$103	$105	$624	$630	$ 22	$ 23	$ 11	$ 11	$13	$ 14
Expected return on plan assets	(127)	(131)	(700)	(701)	—	—	—	—	—	—
Amortization of prior service credit	—	—	—	—	—	—	(20)	(20)	—	—
Amortization of net loss	106	103	131	128	22	22	17	17	—	—
Net periodic cost (benefit)	82	77	55	57	44	45	8	8	13	14
Amortization of pre-merger regulatory asset	—	—	191	191	—	—	—	—	2	2
Total periodic cost	$82	$77	$246	$248	$ 44	$ 45	$ 8	$ 8	$15	$ 16

	Chesapeake Pension Plan		FPU Pension Plan		Chesapeake SERP		Chesapeake Postretirement Plan		FPU Medical Plan	
For the Six Months Ended June 30,	2017	2016	2017	2016	2017	2016	2017	2016	2017	2016
(in thousands)										
Interest cost	206	$210	1,247	$1,259	$ 44	$ 46	$ 21	$ 21	$26	$ 28
Expected return on plan assets	(254)	(261)	(1,399)	(1,402)	—	—	—	—	—	—
Amortization of prior service credit	—	—	—	—	—	—	(39)	(40)	—	—
Amortization of net loss	213	206	262	257	44	44	32	34	—	—
Net periodic cost (benefit)	165	155	110	114	88	90	14	15	26	28
Amortization of pre-merger regulatory asset	—	—	381	381	—	—	—	—	4	4
Total periodic cost	$165	$155	$491	$495	$ 88	$ 90	$ 14	$ 15	$30	$ 32

We expect to record pension and postretirement benefit costs of approximately $1.6 million for 2017. Included in these costs is approximately $769,000 related to continued amortization of the FPU pension regulatory asset, which represents the portion attributable to FPU’s regulated energy operations for the changes in funded status that occurred, but were not recognized, as part of net periodic benefit costs prior to the FPU merger in 2009. This was deferred as a regulatory asset by FPU prior to the merger, to be recovered through rates pursuant to a previous order by the Florida PSC. The unamortized balance of this regulatory asset was approximately $1.7 million and approximately $2.1 million at June 30, 2017 and December 31, 2016, respectively.

Pursuant to a Florida PSC order, FPU continues to record as a regulatory asset a portion of the unrecognized pension and postretirement benefit costs related to its regulated operations after the FPU merger. The portion of the unrecognized pension and postretirement benefit costs related to FPU’s unregulated operations and Chesapeake Utilities' operations is recorded to accumulated other comprehensive loss.

The following tables present the amounts included in the regulatory asset and accumulated other comprehensive loss that were recognized as components of net periodic benefit cost during the three months ended June 30, 2017 and 2016:

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For the Three Months Ended June 30, 2017	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (20)	$ —	$ (20)
Net loss	106	131	22	17	—	276
Total recognized in net periodic benefit cost	106	131	22	(3)	—	256
Recognized from accumulated other comprehensive loss [1]	106	25	22	(3)	—	150
Recognized from regulatory asset	—	106	—	—	—	106
Total	$ 106	$ 131	$ 22	$ (3)	$ —	$ 256

For the Three Months Ended June 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (20)	$ —	$ (20)
Net loss	103	128	22	17	—	270
Total recognized in net periodic benefit cost	103	128	22	(3)	—	250
Recognized from accumulated other comprehensive loss [1]	103	24	22	(3)	—	146
Recognized from regulatory asset	—	104	—	—	—	104
Total	$ 103	$ 128	$ 22	$ (3)	$ —	$ 250

For the Six Months Ended June 30, 2017	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (39)	$ —	$ (39)
Net loss	213	262	44	32	—	551
Total recognized in net periodic benefit cost	213	262	44	(7)	—	512
Recognized from accumulated other comprehensive loss [1]	213	50	44	(7)	—	300
Recognized from regulatory asset	—	212	—	—	—	212
Total	$ 213	$ 262	$ 44	$ (7)	$ —	$ 512

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For the Six Months Ended June 30, 2016	Chesapeake Pension Plan	FPU Pension Plan	Chesapeake SERP	Chesapeake Postretirement Plan	FPU Medical Plan	Total
(in thousands)						
Prior service credit	$ —	$ —	$ —	$ (40)	$ —	$ (40)
Net loss	206	257	44	34	—	541
Total recognized in net periodic benefit cost	206	257	44	(6)	—	501
Recognized from accumulated other comprehensive loss [1]	206	49	44	(6)	—	293
Recognized from regulatory asset	—	208	—	—	—	208
Total	$ 206	$ 257	$ 44	$ (6)	$ —	$ 501

[1] See Note 7, Stockholder's Equity.

During the three and six months ended June 30, 2017, we contributed approximately $119,000 and $167,000, respectively, to the Chesapeake Pension Plan and approximately $1.2 million and $1.5 million, respectively, to the FPU Pension Plan. We expect to contribute a total of approximately $746,000 and approximately $3.0 million to the Chesapeake Pension Plan and FPU Pension Plan, respectively, during 2017, which represents the minimum annual contribution payments required.

The Chesapeake SERP, the Chesapeake Postretirement Plan and the FPU Medical Plan are unfunded and are expected to be paid out of our general funds. Cash benefits paid under the Chesapeake SERP for the three and six months ended June 30, 2017, were approximately $38,000 and approximately $76,000, respectively. We expect to pay total cash benefits of approximately $151,000 under the Chesapeake Pension SERP in 2017. Cash benefits paid under the Chesapeake Postretirement Plan, primarily for medical claims for the three and six months ended June 30, 2017, were approximately $17,000 and approximately $65,000, respectively. We estimate that approximately $83,000 will be paid for such benefits under the Chesapeake Postretirement Plan in 2017. Cash benefits paid under the FPU Medical Plan, primarily for medical claims for the three and six months ended June 30, 2017, were approximately $18,000 and approximately $36,000, respectively. We estimate that approximately $129,000 will be paid for such benefits under the FPU Medical Plan in 2017.

9. Investments

The investment balances at June 30, 2017 and December 31, 2016, consisted of the following:

(in thousands)	June 30, 2017	December 31, 2016
Rabbi trust (associated with the Deferred Compensation Plan)	$5,930	$ 4,881
Investments in equity securities	22	21
Total	$5,952	4,902

We classify these investments as trading securities and report them at their fair value. For the three months ended June 30, 2017 and 2016, we recorded a net unrealized gain of $181,000 and $71,000, respectively, in other income (expense), net in the condensed consolidated statements of income related to these investments. For the six months ended June 30, 2017 and 2016, we recorded an unrealized gain of approximately $433,000 and approximately $53,000, respectively, in other income (expense), net in the condensed consolidated statements of income related to these investments. For the investment in the Rabbi Trust, we also have recorded an associated liability, which is included in other pension and benefit costs in the condensed consolidated balance sheets and is adjusted each month for the gains and losses incurred by the investments in the Rabbi Trust.

10. Share-Based Compensation

Our non-employee directors and key employees are granted share-based awards through our SICP. We record these share-based awards as compensation costs over the respective service period for which services are received in exchange for an award of equity or equity-based compensation. The compensation cost is based primarily on the fair value of the shares

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awarded, using the estimated fair value of each share on the date it was granted and the number of shares to be issued at the end of the service period.
The table below presents the amounts included in net income related to share-based compensation expense for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
(in thousands)				
Awards to non-employee directors	$136	$145	$271	$310
Awards to key employees	37	470	541	954
Total compensation expense	173	615	812	1,264
Less: tax benefit	(70)	(248)	(327)	(509)
Share-based compensation amounts included in net income	$103	$367	$485	$755

Non-employee Directors
Shares granted to non-employee directors are issued in advance of the directors' service periods and are fully vested as of the grant date. We record a prepaid expense equal to the fair value of the shares issued and amortize the expense equally over a service period of one year. In May 2017, each of our non-employee directors received an annual retainer of 835 shares of common stock under the SICP for service as a director through the 2018 Annual Meeting of Stockholders.
A summary of the stock activity for our non-employee directors during the six months ended June 30, 2017 is presented below:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2016	—	$ —
Granted	7,515	$ 71.80
Vested	(7,515)	$ 71.80
Outstanding— June 30, 2017	—	$ —

At June 30, 2017, there was approximately $448,000 of unrecognized compensation expense related to these awards. This expense will be recognized over the directors' remaining service period ending April 30, 2018.
Key Employees
The table below presents the summary of the stock activity for awards to key employees for the six months ended June 30, 2017:

	Number of Shares	Weighted Average Fair Value
Outstanding— December 31, 2016	115,091	$ 51.85
Granted	52,355	$ 67.47
Vested	(32,926)	$ 38.88
Expired	(1,878)	$ 39.97
Outstanding— June 30, 2017	132,642	$ 54.13

In February and May 2017, our Board of Directors granted awards of 52,355 shares of common stock to key employees under the SICP. The shares granted in February and May 2017 are multi-year awards that will vest at the end of the three-year service period ending December 31, 2019. All of these stock awards are earned based upon the successful achievement of long-term goals, growth and financial results, which comprise both market-based and performance-based conditions or targets. The fair value of each performance-based condition or target is equal to the market price of our common stock on the grant date of each award. For the market-based conditions, we used the

Black-Scholes pricing model to estimate the fair value of each market-based award granted.

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At the election of certain of our executives, in March 2017, we withheld shares with a value at least equivalent to each such executive's minimum statutory obligation for applicable income and other employment taxes, remitted the cash to the appropriate taxing authorities, and paid the balance of such shares to each such executive. We withheld 10,269 shares, based on the value of the shares on their award date, determined by the average of the high and low prices of our common stock. Total combined payments for the employees' tax obligations to the taxing authorities were approximately $692,000.

At June 30, 2017, the aggregate intrinsic value of the SICP awards granted to key employees was approximately $9.9 million. At June 30, 2017, there was approximately $3.3 million of unrecognized compensation cost related to these awards, which is expected to be recognized from 2017 through 2019.

Stock Options

We did not have any stock options outstanding at June 30, 2017 or 2016, nor were any stock options issued during these periods.

11. Derivative Instruments

We use derivative and non-derivative contracts to engage in trading activities and manage risks related to obtaining adequate supplies and the price fluctuations of natural gas, electricity and propane. Our natural gas, electric and propane distribution operations have entered into agreements with suppliers to purchase natural gas, electricity and propane for resale to our customers. Aspire Energy has entered into contracts with producers to secure natural gas to meet its obligations. Purchases under these contracts typically either do not meet the definition of derivatives or are considered "normal purchases and normal sales" and are accounted for on an accrual basis. Our propane distribution and natural gas marketing operations may also enter into fair value hedges of their inventory or cash flow hedges of their future purchase commitments in order to mitigate the impact of wholesale price fluctuations. As of June 30, 2017, our natural gas and electric distribution operations did not have any outstanding derivative contracts.

Hedging Activities in 2017

In 2017, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 6.3 million gallons expected to be purchased from July 2017 through September 2018. Under the swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in July 2017 through September 2018) and the swap prices of $0.5975 and $0.7025 per gallon, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap price, Sharp will pay the difference. We accounted for these swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At June 30, 2017, the swap agreements had a fair value asset of approximately $30,000 and a fair value liability of approximately $177,000. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss).

PESCO enters into natural gas futures contracts associated with the purchase and sale of natural gas to other specific customers. These contracts have a two-year term, and we have accounted for them as cash flow hedges. There is no ineffective portion of these hedges. At June 30, 2017, PESCO had a total of 2.6 million Dts hedged under natural gas futures contracts, with a liability fair value of approximately $11,000. The change in fair value of the natural gas futures contracts is recorded as unrealized gain (loss) in other comprehensive income (loss).

The impact of PESCO's financial instruments that have not been designated as hedges on our condensed consolidated financial statements for the six months ended June 30, 2017 was $127,000, which was recorded as an increase in gas costs and is associated with 243,000 Dts of natural gas. This presentation does not reflect the expected gains or losses arising from the underlying physical transactions associated with these financial instruments.

Hedging Activities in 2016

In 2016, Sharp entered into swap agreements to mitigate the risk of fluctuations in wholesale propane index prices associated with 4.8 million gallons expected to be purchased through September 2017, of which 720,000 gallons were outstanding at June 30, 2017. Under the swap agreements, Sharp will receive the difference between the index prices (Mont Belvieu prices in October 2016 through September 2017) and the swap prices of $0.5225 and $0.5650 per gallon, to the extent the index prices exceed the swap prices. If the index prices are lower than the swap price, Sharp will pay the difference. We accounted for these swap agreements as cash flow hedges, and there is no ineffective portion of these hedges. At June 30, 2017, the remaining swap agreements had a fair value asset of approximately $67,000. The change in the fair value of the swap agreements is recorded as unrealized gain (loss) in other comprehensive income (loss).

In December 2016, Sharp paid a total of $33,000 to purchase a put option to protect against a decline in propane prices and related potential inventory losses associated with 630,000 gallons for its propane price cap program in the 2016-2017 heating season. The put option expired without being exercised because the propane prices did not fall below the strike

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price of $0.5650 per gallon in December 2016, January 2017, or February 2017. We accounted for the put option as a fair value hedge, and there was no ineffective portion of this hedge.

In January 2016, PESCO entered into a supplier agreement with Columbia Gas to provide natural gas supply for one of its local distribution customer pools. PESCO also assumed the obligation to store natural gas inventory to satisfy its obligations under the supplier agreement, which terminated on March 31, 2017. In conjunction with the supplier agreement, PESCO entered into natural gas futures contracts during the second quarter of 2016 in order to protect its natural gas inventory against market price fluctuations. We had previously accounted for these contracts as fair value hedges with any ineffective portion being reported directly in earnings and offset by any associated gain (loss) on the inventory value being hedged. During the third quarter of 2016, we discontinued hedge accounting as the hedges were no longer highly effective. As of June 30, 2017, these contracts have all expired and are no longer reported on the balance sheet.

Commodity Contracts for Trading Activities

Shortly after the first quarter of 2017, Xeron wound down its operations. Xeron was previously engaged in trading activities using forward and futures contracts for propane and crude oil. These contracts were considered derivatives and were accounted for using the mark-to-market method of accounting. As of June 30, 2017, Xeron had no outstanding contracts that were accounted for as derivatives.

The following tables present information about the fair value and related gains and losses of our derivative contracts. We did not have any derivative contracts with a credit risk-related contingency. The fair values of the derivative contracts recorded in the condensed consolidated balance sheets as of June 30, 2017 and December 31, 2016, are as follows:

	Asset Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Propane swap agreements	Mark-to-market energy assets	$4	$ 8
Put options	Mark-to-market energy assets	—	9
Derivatives designated as cash flow hedges			
Natural gas futures contracts	Mark-to-market energy assets	128	113
Propane swap agreements	Mark-to-market energy assets	97	693
Total asset derivatives		$229	$ 823

	Liability Derivatives		
		Fair Value As Of	
(in thousands)	Balance Sheet Location	June 30, 2017	December 31, 2016
Derivatives not designated as hedging instruments			
Propane swap agreements	Mark-to-market energy liabilities	$177	$ —
Natural gas futures contracts	Mark-to-market energy liabilities	11	773
Total liability derivatives		$188	$ 773

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The effects of gains and losses from derivative instruments on the condensed consolidated financial statements are as follows:

		Amount of Gain (Loss) on Derivatives:			
	Location of Gain	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
(in thousands)	(Loss) on Derivatives	2017	2016	2017	2016
Derivatives not designated as hedging instruments					
Realized gain on forward contracts and options [1]	Revenue	$ —	$ 88	$ 112	$ 275
Unrealized gain on forward contracts [1]	Revenue	—	1	—	2
Natural gas futures contracts	Cost of sales	497	—	621	—
Propane swap agreements	Cost of sales	—	—	(4)	—
Derivatives designated as fair value hedges					
Put /Call option [2]	Cost of sales	—	—	$ (9)	73
Natural gas futures contracts	Natural Gas Inventory	—	(233)	—	(233)
Derivatives designated as cash flow hedges					
Propane swap agreements	Cost of sales	77	—	465	(364)
Propane swap agreements	Other Comprehensive Income (Loss)	(218)	23	(775)	23
Natural gas futures contracts	Cost of sales	631	211	1,781	359
Natural gas futures contracts	Other Comprehensive Income (Loss)	(1,211)	786	(124)	472
Total		$ (224)	$ 876	$ 2,067	$ 607

(1) All of the realized and unrealized gain on forward contracts represents the effect of trading activities on our condensed consolidated statements of income.

(2) As a fair value hedge with no ineffective portion, the unrealized gains and losses associated with this call option are recorded in cost of sales, offset by the corresponding change in the value of propane inventory (hedged item), which is also recorded in cost of sales. The amounts in cost of sales offset to zero, and the unrealized gains and losses of this put option effectively changed the value of propane inventory.

12. Fair Value of Financial Instruments

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation methods used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). The three levels of the fair value hierarchy are the following:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities;

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability; and

Level 3: Prices or valuation techniques requiring inputs that are both significant to the fair value measurement and unobservable (i.e. supported by little or no market activity).

Financial Assets and Liabilities Measured at Fair Value

The following table summarizes our financial assets and liabilities that are measured at fair value on a recurring basis and the fair value measurements, by level, within the fair value hierarchy as of June 30, 2017 and December 31, 2016:

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As of June 30, 2017	Fair Value	Fair Value Measurements Using: Quoted- Prices- in Active Markets (Level 1)	Significant- Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 22	$22	$ —	$ —
Investments—guaranteed income fund	630	—	—	630
Investments—mutual funds and other	5,300	5,300	—	—
Total investments	5,952	5,322	—	630
Mark-to-market energy assets, incl. natural gas futures contracts and swap agreements	229	—	229	—
Total assets	$ 6,181	$5,322	$ 229	$ 630
Liabilities:				
Mark-to-market energy liabilities including natural gas futures contracts	$ 188	$—	$ 188	$ —

As of December 31, 2016	Fair Value	Fair Value Measurements Using: Quoted- Prices- in Active Markets (Level 1)	Significant- Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
(in thousands)				
Assets:				
Investments—equity securities	$ 21	$21	$ —	$ —
Investments—guaranteed income fund	561	—	—	561
Investments—mutual funds and other	4,320	4,320	—	—
Total investments	4,902	4,341	—	561
Mark-to-market energy assets, incl. natural gas futures contracts and swap agreements	823	—	823	—
Total assets	$ 5,725	$4,341	$ 823	$ 561
Liabilities:				
Mark-to-market energy liabilities including natural gas futures contracts	$ 773	$—	$ 773	$ —

The following valuation techniques were used to measure the fair value of assets and liabilities in the tables above:
Level 1 Fair Value Measurements:
Investments - equity securities — The fair values of these trading securities are recorded at fair value based on unadjusted quoted prices in active markets for identical securities.
Investments - mutual funds and other — The fair values of these investments, comprised of money market and mutual funds, are recorded at fair value based on quoted net asset values of the shares.
Level 2 Fair Value Measurements:
Mark-to-market energy assets and liabilities — The fair values of forward contracts are measured using market transactions in either the listed or OTC markets. The fair value of the propane put/call options, swap agreements and natural gas futures contracts are measured using market transactions for similar assets and liabilities in either the listed or OTC markets.

Level 3 Fair Value Measurements:

Investments - guaranteed income fund — The fair values of these investments are recorded at the contract value, which approximates their fair value.

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The following table sets forth the summary of the changes in the fair value of Level 3 investments for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
	2017	2016
(in thousands)		
Beginning Balance	$561	$279
Purchases and adjustments	65	112
Transfers	—	88
Distribution	—	(8)
Investment income	4	4
Ending Balance	$630	$475

Investment income from the Level 3 investments is reflected in other income (expense) in the accompanying condensed consolidated statements of income.

At June 30, 2017, there were no non-financial assets or liabilities required to be reported at fair value. We review our non-financial assets for impairment at least on an annual basis, as required.

Other Financial Assets and Liabilities

Financial assets with carrying values approximating fair value include cash and cash equivalents and accounts receivable. Financial liabilities with carrying values approximating fair value include accounts payable and other accrued liabilities and short-term debt. The fair value of cash and cash equivalents is measured using the comparable value in the active market and approximates its carrying value (Level 1 measurement). The fair value of short-term debt approximates the carrying value due to its short maturities and because interest rates approximate current market rates (Level 3 measurement).

At June 30, 2017, long-term debt, including current maturities but excluding a capital lease obligation, had a carrying value of approximately $211.4 million. This compares to a fair value of approximately $223.9 million, using a discounted cash flow methodology that incorporates a market interest rate based on published corporate borrowing rates for debt instruments with similar terms and average maturities, and with adjustments for duration, optionality, and risk profile. At December 31, 2016, long-term debt, including the current maturities but excluding a capital lease obligation, had a carrying value of approximately $145.9 million, compared to the estimated fair value of approximately $161.5 million. The valuation technique used to estimate the fair value of long-term debt would be considered a Level 3 measurement.

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13. Long-Term Debt

Our outstanding long-term debt is shown below:

(in thousands)	June 30, 2017	December 31, 2016
FPU secured first mortgage bonds [1] :		
9.08% bond, due June 1, 2022	$7,980	$ 7,978
Uncollateralized senior notes:		
6.64% note, due October 31, 2017	2,727	2,727
5.50% note, due October 12, 2020	8,000	8,000
5.93% note, due October 31, 2023	19,500	21,000
5.68% note, due June 30, 2026	26,100	29,000
6.43% note, due May 2, 2028	7,000	7,000
3.73% note, due December 16, 2028	20,000	20,000
3.88% note, due May 15, 2029	50,000	50,000
3.25% note, due April 30, 2032	70,000	—
Promissory notes	97	168
Capital lease obligation	2,777	3,471
Less: debt issuance costs	(467)	(291)
Total long-term debt	213,714	149,053
Less: current maturities	(12,124)	(12,099)
Total long-term debt, net of current maturities	$201,590	$ 136,954

[1] FPU secured first mortgage bonds are guaranteed by Chesapeake Utilities.

Shelf Agreements

In October 2015, we entered into the Prudential Shelf Agreement, under which we may request that Prudential purchase, through October 8, 2018, up to $150.0 million of our Prudential Shelf Notes. The Prudential Shelf Notes have a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance. Prudential is under no obligation to purchase any of the Prudential Shelf Notes. The interest rate and terms of payment of any series of the Prudential Shelf Notes will be determined at the time of purchase.

In May 2016, Prudential confirmed and accepted our request that Prudential purchase $70.0 million of 3.25 percent Prudential Shelf Notes, which were issued on April 21, 2017. The proceeds received from this issuance of Prudential Shelf Notes were used to reduce short-term borrowings under the Revolver. The balance under the Revolver had accumulated over time as capital expenditures were temporarily financed.

The Prudential Shelf Agreement sets forth certain business covenants to which we are subject when any Prudential Shelf Note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

In March 2017, we entered into the MetLife Shelf Agreement and the NYL Shelf Agreement, under which we may request that MetLife and NYL, through March 2, 2020, purchase up to $150.0 million and $100 million, respectively, of our unsecured senior debt. The unsecured senior debt would have a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance. MetLife and NYL are under no obligation to purchase any unsecured senior debt. The interest rate and terms of payment of any series of unsecured senior debt will be determined at the time of purchase. As of June 30, 2017, no unsecured senior debt has been issued under the MetLife and NYL Shelf Agreements.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis of Financial Condition and Results of Operations is designed to provide a reader of the financial statements with a narrative report on our financial condition, results of operations and liquidity. This discussion and analysis should be read in conjunction with the attached unaudited condensed consolidated financial statements and notes thereto and our Annual Report on Form 10-K for the year ended December 31, 2016, including the audited consolidated financial statements and notes thereto.

Safe Harbor for Forward-Looking Statements

We make statements in this Quarterly Report on Form 10-Q that do not directly or exclusively relate to historical facts. Such statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. One can typically identify forward-looking statements by the use of forward-looking words, such as "project," "believe," "expect," "anticipate," "intend," "plan," "estimate," "continue," "potential," "forecast" or other similar wo or conditional verbs such as "may," "will," "should," "would" or "could." These statements represent our intentions, plans, expectations, assumptions and beliefs about future financial performance, business strategy, projected plans and objectives of the Company. These statements are subject to many risks, uncertainties and other important factors that could cause actual results to differ materially from those expressed in the forward-looking statements. Such factors include, but are not limited to:

- state and federal legislative and regulatory initiatives (including deregulation) that affect cost and investment recovery, have an impact on rate structures and affect the speed at, and the degree to, which competition enters the electric and natural gas industries;
- the outcomes of regulatory, tax, environmental and legal matters, including whether pending matters are resolved within current estimates and whether the costs associated with such matters are adequately covered by insurance or recoverable in rates;
- the timing of certificate authorizations associated with new capital projects;
- changes in environmental and other laws and regulations to which we are subject and environmental conditions of property that we now or may in the future own or operate;
- possible increased federal, state and local regulation of the safety of our operations;
- general economic conditions, including any potential effects arising from terrorist attacks and any hostilities or other external factors over which we have no control;
- industrial, commercial and residential growth or contraction in our markets or service territories;
- the weather and other natural phenomena, including the economic, operational and other effects of hurricanes, ice storms and other damaging weather events;
- the timing and extent of changes in commodity prices and interest rates;
- the ability to establish and maintain key supply sources;
- the effect of spot, forward and future market prices on our various energy businesses;
- the effect of competition on our businesses;
- the capital-intensive nature of our regulated energy businesses;
- the extent of our success in connecting natural gas and electric supplies to transmission systems and in expanding natural gas and electric markets;
- the ability to construct facilities at or below estimated costs and within projected time frames;
- the creditworthiness of counterparties with which we are engaged in transactions;
- the results of financing efforts, including our ability to obtain financing on favorable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- the ability to successfully execute, manage and integrate merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the impact on our cost and funding obligations under our pension and other post-retirement benefit plans of potential downturns in the financial markets, lower discount rates, and costs associated with the Patient Protection and Affordable Care Act;

- the ability to continue to hire, train and retain appropriately qualified personnel;
- the effect of accounting pronouncements issued periodically by accounting standard-setting bodies;
- the timing and success of technological improvements;
- risks related to cyber-attacks that could disrupt our business operations or result in failure of information technology systems; and
- the impact of significant changes to current tax regulations and rates.

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Introduction

We are a diversified energy company engaged, directly or through our operating divisions and subsidiaries, in regulated and unregulated energy businesses.

Our strategy is focused on growing earnings from a stable utility foundation and investing in related businesses and services that provide opportunities for returns greater than traditional utility returns. We are focused on identifying and developing opportunities across the energy value chain, with emphasis on midstream and downstream investments that are accretive to earnings per share and consistent with our long-term growth strategy.

The key elements of this strategy include:

- executing a capital investment program in pursuit of growth opportunities that generate returns equal to or greater than our cost of capital;
- expanding our energy distribution and transmission businesses organically as well as into new geographic areas;
- providing new services in our current service territories;
- expanding our footprint in potential growth markets through strategic acquisitions;
- entering new unregulated energy markets and business lines that will complement our existing operating units and growth strategy while capitalizing on opportunities across the energy value chain; and
- differentiating the Company as a full-service energy supplier/partner/provider through a customer-centric model.

Due to the seasonality of our business, results for interim periods are not necessarily indicative of results for the entire fiscal year. Revenue and earnings are typically greater during the first and fourth quarters, when consumption of energy is normally highest due to colder temperatures.

The following discussions and those elsewhere in this Quarterly Report on Form 10-Q on operating income and segment results include the use of the term “gross margin", which is determined by deducting the cost of sales from operating revenue. Cost of sales includes the purchased cost of natural gas, electricity and propane and the cost of labor spent on direct revenue-producing activities, and excludes depreciation, amortization and accretion. Gross margin should not be considered an alternative to operating income or net income, which are determined in accordance with GAAP. We believe that gross margin, although a non-GAAP measure, is useful and meaningful to investors as a basis for making investment decisions. It provides investors with information that demonstrates the profitability achieved by us under our allowed rates for regulated operations and under our competitive pricing structure for non-regulated segments. Our management uses gross margin in measuring its business units’ performance and has historically analyzed and reported gross margin information publicly. Other companies may calculate gross margin in a different manner.

Unless otherwise noted, earnings per share information is presented on a diluted basis.

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Results of Operations for the Three and Six Months ended June 30, 2017

Overview and Highlights

Our net income for the quarter ended June 30, 2017 was $6.0 million, or $0.37 per share. This represents a decrease of $2.0 million, or $0.15 per share, compared to net income of $8.0 million, or $0.52 per share, reported for the same quarter in 2016. Operating income decreased $2.1 million for the three months ended June 30, 2017.

	Three Months Ended June 30, 2017	2016	Increase (decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$13,730	$15,226	$(1,496)
Unregulated Energy segment	(38)	412	(450)
Other businesses and eliminations	(26)	104	(130)
Operating Income	$13,666	$15,742	$(2,076)
Other expense, net	(607)	(8)	(599)
Interest charges	3,073	2,624	449
Pre-tax Income	9,986	13,110	(3,124)
Income taxes	3,940	5,081	(1,141)
Net Income	$6,046	$8,029	$(1,983)
Earnings Per Share of Common Stock			
Basic	$0.37	$0.52	$(0.15)
Diluted	$0.37	$0.52	$(0.15)

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Key variances, between the second quarter of 2017 and the second quarter of 2016, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Second Quarter of 2016 Reported Results	$13,110	$8,029	$ 0.52
Adjusting for unusual items:			
Weather impact	(675)	(409)	(0.03)
Wind-down of Xeron operations	(351)	(213)	(0.01)
	(1,026)	(622)	(0.04)
Increased (Decreased) Gross Margins:			
Eight Flags' CHP plant*	2,128	1,289	0.08
GRIP*	532	322	0.02
Service expansions*	478	289	0.02
Natural gas marketing	(450)	(272)	(0.02)
Natural gas growth (excluding service expansions)	325	197	0.01
Pricing amendments to Aspire Energy's long-term agreements	271	164	0.01
	3,284	1,989	0.12
Increased Other Operating Expenses:			
Higher depreciation, asset removal and property tax costs due to new capital investments	(1,337)	(810)	(0.05)
Eight Flags' operating expenses	(1,260)	(763)	(0.05)
Higher staffing and associated costs	(976)	(591)	(0.04)
Higher outside services and facilities maintenance costs	(335)	(203)	(0.01)
Higher regulatory expenses	(295)	(179)	(0.01)
	(4,203)	(2,546)	(0.16)
Interest charges	(449)	(272)	(0.02)
Change in other expense	(253)	(153)	(0.01)
Net other changes	(477)	(379)	(0.02)
	(1,179)	(804)	(0.05)
EPS impact of increase in outstanding shares due to September 2016 offering	—	—	(0.02)
Second Quarter of 2017 Reported Results	$9,986	$6,046	$ 0.37

*See the Major Projects and Initiatives table.

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Our net income for the six months ended June 30, 2017 was $25.2 million, or $1.54 per share. This represents a decrease of $3.2 million, or $0.31 per share, compared to net income of $28.4 million, or $1.85 per share, reported for the same period in 2016. Operating income decreased $3.8 million for the six months ended June 30, 2017.

	Six Months Ended June 30,		Increase
	2017	2016	(decrease)
(in thousands except per share)			
Business Segment:			
Regulated Energy segment	$36,747	$39,545	$(2,798)
Unregulated Energy segment	11,492	12,347	(855)
Other businesses and eliminations	102	230	(128)
Operating Income	$48,341	$52,122	$(3,781)
Other expense, net	(884)	(42)	(842)
Interest charges	5,811	5,274	537
Pre-tax Income	41,646	46,806	(5,160)
Income taxes	16,456	18,410	(1,954)
Net Income	$25,190	$28,396	$(3,206)
Earnings Per Share of Common Stock			
Basic	$1.54	$1.86	$(0.32)
Diluted	$1.54	$1.85	$(0.31)

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Key variances, between the six months ended 2017 and the six months ended 2016, included:

(in thousands, except per share data)	Pre-tax Income	Net Income	Earnings Per Share
Six Months Ended June 30, 2016 Reported Results	$46,806	$28,396	$ 1.85
Adjusting for unusual items:			
Weather impact	(1,363)	(825)	(0.05)
Wind-down of Xeron operations	(886)	(536)	(0.03)
	(2,249)	(1,361)	(0.08)
Increased (Decreased) Gross Margins:			
Eight Flags' CHP plant*	4,424	2,676	0.17
Natural gas marketing	1,704	1,031	0.07
Service expansions*	1,237	748	0.05
GRIP*	1,213	734	0.05
Natural gas growth (excluding service expansions)	1,130	683	0.04
Pricing amendments to Aspire Energy's long-term agreements	844	510	0.03
Implementation of Delaware Division new rates*	417	252	0.02
Lower retail propane margins	(305)	(184)	(0.01)
	10,664	6,450	0.42
Increased Other Operating Expenses:			
Higher depreciation, asset removal and property tax costs due to new capital investments	(2,696)	(1,631)	(0.11)
Eight Flags' operating expenses	(2,528)	(1,529)	(0.10)
Higher payroll expense	(2,219)	(1,342)	(0.09)
Higher outside services and facilities maintenance costs	(2,054)	(1,243)	(0.08)
Higher benefits and other employee-related expenses	(1,966)	(1,189)	(0.08)
Higher regulatory expenses	(664)	(401)	(0.03)
	(12,127)	(7,335)	(0.49)
Interest charges	(537)	(325)	(0.02)
Change in other expense	(476)	(288)	(0.02)
Net other changes	(435)	(347)	(0.02)
	(1,448)	(960)	(0.06)
EPS impact of increase in outstanding shares due to September 2016 offering	—	—	(0.10)
Six Months Ended June 30, 2017 Reported Results	$41,646	$25,190	$ 1.54

*See the Major Projects and Initiatives table.

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Summary of Key Factors
Major Projects and Initiatives
The following table summarizes gross margin for our major projects and initiatives recently completed and initiatives currently underway, but which will be completed in the future. Gross margin reflects operating revenue less cost of sales, excluding depreciation, amortization and accretion (dollars in thousands):

	Gross Margin for the Period									
	Three Months Ended			Six Months Ended			Year Ended			
	June 30,			June 30,			December 31,	Estimate for		
	2017	2016	Variance	2017	2016	Variance	2016	2017	2018	2019
Major Projects and Initiatives Recently Completed										
Capital Investment Projects	$9,601	$6,463	$3,138	$18,922	$12,049	$6,873	$29,819	$35,393	$32,125	$33,035
Settled Delaware Division Rate Case	425	555	(130)	1,295	878	417	1,487	2,250	2,250	2,250
Total Major Projects and Initiatives Recently Completed	10,026	7,018	3,008	20,217	12,927	7,290	31,306	37,643	34,375	35,285
Future Major Projects and Initiatives										
Capital Investment Projects										
2017 Eastern Shore System Expansion	—	—	—	—	—	—	—	126	9,313	15,799
Northwest Florida Expansion	—	—	—	—	—	—	—	—	3,970	5,100
Eastern Shore System Reliability [1]	—	—	—	—	—	—	—	1,875	4,500	4,500
Total Future Major Projects and Initiatives	—	—	—	—	—	—	—	2,001	17,783	25,399
Total	$10,026	$7,018	$3,008	$20,217	$12,927	$7,290	$31,306	$39,644	$52,158	$60,684

[1] In January 2017, Eastern Shore filed a rate case with the FERC. The outcome of the rate case is not known at this time. See Note 3, Rates and Other Regulatory Activities, for additional information. This table assumes recovery in the rate case of the costs of the System Reliability Project only, as discussed in further detail below.

Major Projects and Initiatives Recently Completed
The following table summarizes gross margin generated by our major projects and initiatives recently completed (dollars in thousands):

	Gross Margin for the Period [1]									
	Three Months Ended			Six Months Ended			Year Ended			
	June 30,			June 30,			December 31,	Estimate for		
	2017	2016	Variance	2017	2016	Variance	2016	2017	2018	2019

Capital Investment Projects:										
Service Expansions:										
Short-term contracts (Delaware)	$1,194	$2,648	$(1,454)	$3,857	$5,191	$(1,334)	$11,454	$5,689	$1,407	$1,407
Long-term contracts (Delaware)	2,387	455	1,932	3,481	911	2,570	1,815	7,611	7,605	7,583
Total Service Expansions	3,581	3,103	478	7,338	6,102	1,236	13,269	13,300	9,012	8,990
Florida GRIP	3,341	2,809	532	6,609	5,396	1,213	11,552	13,727	14,407	15,085
Eight Flags' CHP Plant	2,679	551	2,128	4,975	551	4,424	4,998	8,366	8,706	8,960
Total Capital Investment Projects	9,601	6,463	3,138	18,922	12,049	6,873	29,819	35,393	32,125	33,035
Settled Delaware Division Rate Case	425	555	(130)	1,295	878	417	1,487	2,250	2,250	2,250
Total Major Projects and Initiatives Recently Completed	$10,026	$7,018	$3,008	$20,217	$12,927	$7,290	$31,306	$37,643	$34,375	$35,285

(1) Does not include gross margin of $3.5 million and $9.3 million for the three and six months ended June 30, 2017, respectively, and $13.9 million for the year ended December 31, 2016, which consists primarily of gross margin attributable to Aspire Energy for those periods. The acquisition of Aspire Energy was previously disclosed as a major project; however, the gross margin attributable to Aspire Energy is no longer included in this table.

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Service Expansions

In August 2014, Eastern Shore entered into a precedent agreement with an electric power generator in Kent County, Delaware, to provide, upon the satisfaction of certain conditions, a 20-year natural gas transmission service for 45,000 Dts/d deliverable to the lateral serving the customer's facility. In July 2016, the FERC authorized Eastern Shore to construct and operate the project, which consists of 5.4 miles of 16-inch pipeline looping and new compression capability in Delaware. Eastern Shore provided interim services to this customer pending construction of facilities. Construction of the project is complete, and long-term service commenced in March 2017, pursuant to a 20-year OPT 90 ≤ service agreement. This service generated an additional gross margin of $106,000 during the six months ended June 30, 2017 compared to the same period in 2016. There was no incremental margin change during the second quarter as the margin generated from the permanent services equated to the margin generated from providing interim services during the second quarter of 2016. This service is expected to generate gross margin of $7.0 million for 2017 and between $5.8 million and $7.8 million annually through the remaining term of the agreement.

In October 2015, Eastern Shore submitted an application to the FERC to make certain meter tube and control valve replacements and related improvements at its TETLP interconnect facilities, which would enable Eastern Shore to increase natural gas receipts from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. In December 2015, the FERC authorized Eastern Shore to proceed with this project, which was completed and placed in service in March 2016. Approximately 35 percent of the increased capacity has been subscribed on a short-term firm service basis through October 2017. This service generated an additional gross margin of $540,000 and $1.2 million for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016. The remaining capacity is available for firm or interruptible service.

GRIP

GRIP is a natural gas pipe replacement program approved by the Florida PSC, designed to expedite the replacement of qualifying distribution mains and services (any material other than coated steel or plastic) to enhance the reliability and integrity of the Florida natural gas distribution systems. This program allows recovery, through regulated rates, of capital and other program-related costs, inclusive of a return on investment, associated with the replacement of the mains and services. Since the inception of the program in August 2012, we have invested $108.1 million to replace 240 miles of qualifying distribution mains, including $5.2 million during the first six months of 2017. The increased investment in GRIP generated additional gross margin of $532,000 and $1.2 million for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016.

Eight Flags' CHP plant

In June 2016, Eight Flags completed construction of a CHP plant on Amelia Island, Florida. This CHP plant, which consists of a natural-gas-fired turbine and associated electric generator, produces approximately 20 MWH of base load power and includes a heat recovery steam generator capable of providing approximately 75,000 pounds per hour of residual steam. In June 2016, Eight Flags began selling power generated from the CHP plant to FPU, pursuant to a 20-year power purchase agreement for distribution to its retail electric customers. In July 2016, it also started selling steam to the industrial customer that owns the property on which Eight Flags' CHP plant is located, pursuant to a separate 20-year contract.

The CHP plant is powered by natural gas transported by FPU and by Peninsula Pipeline. For the three and six months ended June 30, 2017, Eight Flags and other affiliates of Chesapeake Utilities generated $2.1 million and $4.4 million, respectively, in additional gross margin as a result of these services. This amount includes gross margin of $43,000 and $535,000 for the three and six months ended June 30, 2017, respectively, attributable to natural gas distribution and transportation services provided to the CHP plant by Chesapeake Utilities' regulated affiliates.

Major Projects and Initiatives Currently Underway

Northwest Florida Expansion Project: Peninsula Pipeline and Chesapeake Utilities' Florida natural gas division are constructing a pipeline in Escambia County, Florida that will interconnect with FGT's pipeline. The project consists of 33 miles of 12-inch transmission line from the FGT interconnect that will be operated by Peninsula Pipeline and 8 miles of 8-inch lateral distribution lines that will be operated by Chesapeake Utilities' Florida natural gas division. We have entered into agreements to serve two industrial customers. The estimated annual gross margin associated with this project, once in service, is approximately $5.1 million.

2017 Expansion Project: In May 2016, Eastern Shore submitted a request to the FERC to initiate the FERC's pre-filing process for its proposed 2017 Expansion Project. This project, which will expand Eastern Shore's firm service capacity by 26 percent, will provide 61,162 Dts/d of additional firm natural gas transportation service on Eastern Shore's pipeline system with an additional 52,500 Dts/d of firm transportation service at certain Eastern Shore receipt facilities pursuant to precedent agreements Eastern Shore entered into with seven existing customers including three affiliates of the Company. Facilities required to provide this new service will consist of: (i) approximately 23 miles of pipeline looping in Pennsylvania, Maryland and Delaware; (ii) upgrades to existing metering facilities in Lancaster County, Pennsylvania; (iii) installation of an additional 3,750-horsepower compressor unit at Eastern Shore’s existing Daleville compressor station in Chester County, Pennsylvania; and (iv) approximately 17 miles of new mainline extension and two pressure control stations in Sussex County, Delaware. The project will generate approximately

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$15.8 million of gross margin in the first full year after the new transportation services go into effect. The estimated investment in this expansion project is $98.6 million.
System Reliability Project: In July 2016, the FERC authorized Eastern Shore to construct and operate its System Reliability Project, which consists of approximately 10.1 miles of 16-inch pipeline looping and auxiliary facilities in New Castle and Kent Counties, Delaware, and a new compressor at its existing Bridgeville compressor station in Sussex County, Delaware. A 2.5 mile looping segment was completed and placed into service in December 2016. The remaining looping and the new compressor were completed and placed into service in the second quarter of 2017. This project was included in Eastern Shore's January 2017 base rate case filing with the FERC. We have assumed recovery of this project's costs beginning in August 2017, coinciding with the proposed effectiveness of new rates, subject to refund pending final resolution of the base rate case. We expect to generate approximately $4.5 million in annual gross margin once new rates go into effect.
Other major factors influencing gross margin

Weather and Consumption
Warmer temperatures in 2017 had a negative impact on our earnings. As compared to the prior year, warmer temperatures during 2017 reduced gross margin for the quarter and six months ended June 30, 2017 by $675,000 and $1.4 million, respectively, compared to the same periods in 2016. Warmer than normal temperatures for the quarter and six months ended June 30, 2017, reduced gross margin by $1.1 million and $4.3 million, respectively, compared to the same periods in 2016. The following table summarizes HDD and CDD variances from the 10-year average HDD/CDD ("Normal") for the three and six months ended June 30, 2017 and 2016.

HDD and CDD Information

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Variance	2017	2016	Variance
Delmarva						
Actual HDD	288	485	(197)	2,246	2,579	(333)
10-Year Average HDD ("Delmarva Normal")	429	452	(23)	2,783	2,854	(71)
Variance from Delmarva Normal	(141)	33		(537)	(275)	
Florida						
Actual HDD	13	9	4	298	514	(216)
10-Year Average HDD ("Florida Normal")	19	19	—	602	553	49
Variance from Florida Normal	(6)	(10)		(304)	(39)	
Ohio						
Actual HDD	508	766	(258)	2,992	3,557	(565)
10-Year Average HDD ("Ohio Normal")	637	630	7	3,774	3,762	12
Variance from Ohio Normal	(129)	136		(782)	(205)	
Florida						
Actual CDD	935	986	(51)	1,080	1,113	(33)
10-Year Average CDD ("Florida CDD Normal")	955	948	7	1,037	1,025	12
Variance from Florida CDD Normal	(20)	38		43	88	

Propane prices
Lower retail propane margins per gallon for our Delmarva and Florida propane distribution operations decreased gross margin by $23,000 and $305,000 for the three and six months ended June 30, 2017, respectively, of which $8,000 and $204,000 is associated with the Delmarva operations. We continue to assume normal levels of margins in our long-term financial plans and forecasts.

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PESCO

PESCO provides natural gas supply and supply management services to residential, commercial, industrial and wholesale customers. PESCO operates primarily in Florida, on the Delmarva Peninsula, and in Ohio. PESCO competes with regulated utilities and other unregulated third-party marketers to manage natural gas supplies directly to residential, commercial and industrial customers through competitively-priced contracts. PESCO does not currently own or operate any natural gas transmission or distribution assets but sells gas that is delivered to retail or wholesale customers through affiliated and non-affiliated local distribution company systems and transmission pipelines.

In 2017, our Delmarva natural gas distribution operations entered into asset management agreements with PESCO to manage a portion of their natural gas transportation and storage capacity. The asset management agreements were effective April 1, 2017, and each has a three-year term, expiring on March 31, 2020. As a result of these agreements, PESCO manages capacity on regional pipelines as well as third-party storage contracts for our Delmarva natural gas distribution operations in conjunction with PESCO's asset management services.

For the three months ended June 30, 2017, PESCO's gross margin decreased by $450,000, due primarily to the absence of a supplier agreement that expired on March 31, 2017 and was not renewed due to our expectation of lower margins. For the six months ended June 30, 2017, PESCO generated additional gross margin of $1.7 million compared to the same period in 2016, as a result of revenues from the supplier agreement as well as additional customers in Florida, partially offset by lower margin in the Mid-Atlantic region. The timing of the deliveries of natural gas under the supplier agreement did not coincide with the payment of storage and pipeline fees. PESCO delivered the highest volumes during the first quarter of 2017, while fixed storage and pipeline fees were paid over the entire twelve-month term of the agreement.

Xeron

As disclosed previously, our management determined that there was no viable strategy to restore Xeron to profitability in the near term and, accordingly, wound up Xeron's operations shortly after the first quarter of 2017. We recorded $522,000 and $1.1 million in pre-tax losses from Xeron in the three and six months ended June 30, 2017, respectively, driven primarily by non-recurring employee severance costs and costs associated with the termination of leased office space in Houston, Texas. We do not anticipate incurring any additional costs that will have a material impact associated with winding down Xeron's operations. With the wind-down of Xeron, the operating loss generated in the latter half of 2016 will be avoided later this year.

Other Natural Gas Growth - Distribution Operations

In addition to service expansions, the natural gas distribution operations on the Delmarva Peninsula generated $128,000 and $649,000 in additional gross margin for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016, due to an increase in residential, commercial and industrial customers served. The average number of residential customers on the Delmarva Peninsula increased by 3.6 percent and 3.8 percent during the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016. The natural gas distribution operations in Florida generated $328,000 and $804,000 in additional gross margin for the three and six months ended June 30, 2017, respectively, compared to the same periods in 2016, due primarily to an increase in commercial and industrial customers in Florida.

Regulatory Proceedings

Delaware Division Rate Case

In December 2016, the Delaware PSC approved a settlement agreement as recommended by the Hearing Examiner's report. The settlement agreement, among other things, provided for an increase in our Delaware division revenue requirement of $2.25 million and a rate of return on common equity of 9.75 percent. The new authorized rates went into effect on January 1, 2017. Any amounts collected through 2016 interim rates in excess of the respective portion of the $2.25 million were refunded to the ratepayers in March 2017.

Eastern Shore Rate Case

In January 2017, Eastern Shore filed a base rate proceeding with the FERC, as required by the terms of its 2012 rate case settlement agreement. Eastern Shore's proposed rates were based on the mainline cost of service of approximately $60.0 million resulting in an overall requested revenue increase of approximately $18.9 million and a requested rate of return on common equity of 13.75 percent. The filing includes incremental rates for the White Oak Mainline

Expansion project, which benefits a single customer. Eastern Shore is also proposing to revise its depreciation rates and negative salvage rate based on the results of independent, third-party depreciation and negative salvage value studies. The FERC issued a notice of the filing in January 2017, and the comment period ended in February 2017. Fourteen parties intervened in the proceeding, with six of those parties filing protests to various aspects of the filing. The FERC issued an order suspending the effectiveness of the proposed tariff rates for the usual five-month period. A settlement conference was held on July 27, 2017, in which the parties reviewed the latest proposals and further discussed

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their positions. Another settlement conference is scheduled for August 30 and 31, 2017. Eastern Shore has filed the requisite notice with the FERC to implement interim rates effective August 1, 2017.

Investing for Future Growth

To support and continue our growth, we have expanded, and will continue to expand, our resources and capabilities. Eastern Shore has expanded, and has announced significant additional expansions to its transmission system, and is therefore increasing its staffing. We requested recovery of most of Eastern Shore's increased staffing costs in its 2017 rate case. Growth in non-regulated businesses, including Aspire Energy, PESCO and Eight Flags, requires additional staff as well as corporate resources to support the increased level of business operations. Finally, to allow us to continue to identify and move growth initiatives forward and to assist in developing additional initiatives, resources have been added in our corporate shared services departments. For the three and six months ended June 30, 2017, our staffing and associated costs increased by $976,000 and $4.2 million, or five percent and 12 percent, respectively, compared to the same periods in 2016. We are prudently managing the pace and magnitude of the investments being made while ensuring that we appropriately expand our human resources and systems capabilities to capitalize on future growth opportunities.

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Regulated Energy Segment

For the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016

	Three Months Ended June 30,		Increase
	2017	2016	(decrease)
(in thousands)			
Revenue	$70,996	$67,395	$3,601
Cost of sales	24,167	21,635	2,532
Gross margin	46,829	45,760	1,069
Operations & maintenance	22,763	21,301	1,462
Depreciation & amortization	7,142	6,267	875
Other taxes	3,194	2,966	228
Other operating expenses	33,099	30,534	2,565
Operating income	$13,730	$15,226	$(1,496)

Operating income for the Regulated Energy segment for the three months ended June 30, 2017 was $13.7 million, a decrease of $1.5 million compared to the same period in 2016. The decreased operating income resulted from increased gross margin of $1.1 million offset by an increase in operating expenses of $2.6 million. Of the total $2.6 million increase in operating expenses, $1.5 million is associated with Eastern Shore's recent growth and planned future growth.

Gross Margin

Items contributing to the quarter-over-quarter increase of $1.1 million, or 2.3 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2016	$45,760
Factors contributing to the gross margin increase for the three months ended June 30, 2017:	
Additional Revenue from GRIP in Florida	532
Service Expansions	478
Customer Consumption - Weather and Other	(355)
Natural Gas Growth (Excluding Service Expansions)	325
Other	89
Gross margin for the three months ended June 30, 2017	$46,829

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Additional Revenue from GRIP in Florida

Increased investment in GRIP generated additional gross margin of $532,000 for the three months ended June 30, 2017, compared to the same period in 2016.

Service Expansions

Increased gross margin of $478,000 was generated primarily from short-term firm service that commenced in March 2016, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP that increased Eastern Shore's natural gas receipt capacity from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. This short-term firm service generated $540,000 of incremental margin. The remaining capacity is available for firm or interruptible service.

Customer Consumption - Weather and Other

Gross margin decreased by $355,000 from lower customer consumption of natural gas, due primarily to warmer temperatures in Florida and on the Delmarva Peninsula. Because Maryland and Sandpiper Energy rates include a weather normalization adjustment for residential heating and smaller commercial heating customers, these operations experienced less of an impact from the warmer weather during the quarter.

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Natural Gas Growth (excluding service expansions)

Increased gross margin of $325,000 from other growth in natural gas (excluding service expansions) was generated primarily from the following:

- $328,000 from Florida natural gas customer growth, due primarily to new services to commercial and industrial customers, and
- $128,000 from a four-percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers;
- which were partially offset by $131,000 in decreased margin from interruptible service for Eastern Shore.

Other Operating Expenses

Other operating expenses increased by $2.6 million. The significant components of the increase in other operating expenses included:

- $1.2 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $358,000 in higher costs related to outside services to support growth and higher facility maintenance costs to maintain system integrity;
- $295,000 in increased regulatory expenses, due primarily to costs associated with Eastern Shore’s rate case filing in 2017; and
- $255,000 in higher benefits and employee-related costs, while payroll costs remained flat in the second quarter of 2017. Since we are self-insured, benefits costs will fluctuate depending upon actual claims experience.

For the Six Months Ended June 30, 2017 compared to the six months ended June 30, 2016

	Six Months Ended June 30,		Increase
	2017	2016	(decrease)
(in thousands)			
Revenue	$168,650	$156,611	$12,039
Cost of sales	64,411	56,540	7,871
Gross margin	104,239	100,071	4,168
Operations & maintenance	46,721	41,761	4,960
Depreciation & amortization	14,027	12,563	1,464
Other taxes	6,744	6,202	542
Other operating expenses	67,492	60,526	6,966
Operating income	$36,747	$39,545	$(2,798)

Operating income for the Regulated Energy segment for the six months ended June 30, 2017 was $36.7 million, a decrease of $2.8 million compared to the same period in 2016. The decreased operating income was due to an increase in gross margin of $4.2 million, which was offset by higher operating expenses of $7.0 million. Of the total $7.0 million increase in operating expenses, $3.8 million is associated with Eastern Shore's recently completed projects as well as initiatives underway.

Gross Margin

Items contributing to the period-over-period increase of $4.2 million, or 4.2 percent, in gross margin are listed in the following table:

(in thousands)	
Gross margin for the six months ended June 30, 2016	$100,071
Factors contributing to the gross margin increase for the six months ended June 30, 2017:	
Service Expansions	1,237
Additional Revenue from GRIP in Florida	1,213
Natural Gas Growth (Excluding Service Expansions)	1,130
Customer Consumption - Weather and Other	(797)
Service to Eight Flags	535
Delaware Division Base Rate Increase	417
Sandpiper System Improvement Rates	239
Other	194
Gross margin for the six months ended June 30, 2017	$104,239

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Service Expansions

Increased gross margin of $1.2 million from natural gas service expansions was generated from Eastern Shore's short-term firm service that commenced in March 2016, following certain measurement and related improvements to Eastern Shore's interconnect with TETLP that increased Eastern Shore's natural gas receipt capacity from TETLP by 53,000 Dts/d, for a total capacity of 160,000 Dts/d. The remaining capacity is available for firm or interruptible service.

Additional Revenue from GRIP in Florida

Increased investment in GRIP generated additional gross margin of $1.2 million for the six months ended June 30, 2017, compared to the same period in 2016.

Natural Gas Growth (excluding service expansions)

Increased gross margin of $1.1 million from other growth in natural gas (excluding service expansions) was generated primarily from the following:

- $804,000 from Florida natural gas customer growth due primarily to new services to commercial and industrial customers, and
- $649,000 from a four-percent increase in the average number of residential customers in the Delmarva natural gas distribution operations, as well as growth in the number of commercial and industrial customers.

Customer Consumption - Weather and Other

Gross margin decreased by $797,000 from lower customer consumption of electricity and natural gas, due primarily to warmer temperatures in Florida and on the Delmarva Peninsula. Because Maryland and Sandpiper Energy rates include a weather normalization adjustment for residential heating and smaller commercial heating customers, these operations experienced less of an impact from the warmer weather during the first six months of 2017.

Service to Eight Flags

We generated additional gross margin of $535,000 in the six months ended June 30, 2017, compared to the same period in 2016, from new natural gas transmission and distribution services provided by our affiliates to Eight Flags' CHP plant.

Implementation of Delaware Division Rates

Our Delaware Division generated additional gross margin of $417,000 as a result of the settlement of the rate case. See Note 3, Rates and Other Regulatory Activities, to the condensed consolidated financial statements for additional details.

Sandpiper System Improvement Rates

Sandpiper generated additional gross margin of $239,000 from higher margins associated with the continued conversion of its distribution system from propane to natural gas.

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Other Operating Expenses

Other operating expenses increased by $7.0 million. The significant components of the increase in other operating expenses included:

- $2.1 million in higher depreciation, asset removal and property tax costs associated with recent capital investments;
- $1.5 million in higher costs related to outside services to support growth and facility maintenance to maintain system integrity;
- $1.3 million in higher payroll expenses for addition personnel to support growth;
- $1.2 million in higher benefits and employee-related costs in 2017 (since we are self-insured, benefits costs will fluctuate depending upon actual claims experience); and
- $664,000 in increased regulatory expenses, due primarily to costs associated with Eastern Shore's rate case filing in 2017.

Unregulated Energy Segment

For the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016

	Three Months Ended June 30,		
	2017	2016	Increase (decrease)
(in thousands)			
Revenue	$63,049	$36,803	$26,246
Cost of sales	49,313	24,726	24,587
Gross margin	13,736	12,077	1,659
Operations & maintenance	11,087	9,771	1,316
Depreciation & amortization	1,929	1,490	439
Other taxes	758	404	354
Total operating expenses	13,774	11,665	2,109
Operating Income	$(38)	$412	$(450)

Operating loss for the Unregulated Energy segment for the three months ended June 30, 2017 was $38,000, which represented a decline in operating income of $450,000 compared to the same period in 2016. The decreased operating income was due to an increase in gross margin of $1.7 million, which was more than offset by a $2.1 million increase in operating expenses.

Gross Margin

Items contributing to the quarter-over-quarter increase of $1.7 million in gross margin are listed in the following table:

(in thousands)	
Gross margin for the three months ended June 30, 2016	$12,077
Factors contributing to the gross margin increase for the three months ended June 30, 2017:	
Eight Flags' CHP Plant	2,085
Natural Gas Marketing	(450)
Customer Consumption - Weather and Other	(368)
Pricing amendments to Aspire Energy's Long-Term Agreements	271
Other	121
Gross margin for the three months ended June 30, 2017	$13,736

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand the information disclosed in the table.

Eight Flags
Eight Flags' CHP plant, which commenced operations in June 2016, generated $2.1 million in additional gross margin.

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Natural Gas Marketing
PESCO's gross margin decreased by $450,000 in the second quarter of 2017 compared to the same period in 2016, due primarily to the absence of the supplier agreement with Columbia Gas that expired on March 31, 2017 and was not renewed due to our expectations of lower margin.
Customer Consumption - Weather and Other
Gross margin decreased by $368,000 due to warmer than normal temperatures on the Delmarva Peninsula, resulting in lower customer consumption of propane.

Pricing Amendments to Aspire Energy Long-Term Agreements
An increase in gross margin of $271,000 was due to pricing amendments to long-term sales agreements.

Other Operating Expenses
Other operating expenses increased by $2.1 million. The significant components of the increase in other operating expenses included:

- $1.3 million incurred by Eight Flags' CHP plant, which commenced operations in June 2016; and
- $645,000 in higher staffing and associated costs for additional personnel to support growth. Since we are self-insured, benefits costs will fluctuate depending upon actual claims experience.

For the six months ended June 30, 2017 compared to the six months ended June 30, 2016

	Six Months Ended June 30,		Increase
	2017	2016	(decrease)
(in thousands)			
Revenue	$155,774	$94,319	$61,455
Cost of sales	115,219	59,141	56,078
Gross margin	40,555	35,178	5,377
Operations & maintenance	23,511	19,162	4,349
Depreciation & amortization	3,833	2,672	1,161
Other taxes	1,719	997	722
Total operating expenses	29,063	22,831	6,232
Operating Income	$11,492	$12,347	$(855)

Operating income for the Unregulated Energy segment for the six months ended June 30, 2017 was $11.5 million, a decrease of $855,000 compared to the same period in 2016. The decreased operating income was due to an increase in gross margin of $5.4 million, which was more than offset by a $6.2 million increase in operating expenses.
Gross Margin
Items contributing to the period-over-period increase of $5.4 million in gross margin are listed in the following table:

(in thousands)	
Gross margin for the six months ended June 30, 2016	$35,178
Factors contributing to the gross margin increase for the six months ended June 30, 2017:	
Eight Flags' CHP Plant	3,889
Natural Gas Marketing	1,704
Pricing amendments to Aspire Energy's Long-Term agreements	844
Customer Consumption - Weather and Other	(836)
Retail Propane Margins	(305)
Other	81
Gross margin for the six months ended June 30, 2017	$40,555

The following is a narrative discussion of the significant items in the foregoing table, which we believe is necessary to understand

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the information disclosed in the table.

Eight Flags

Eight Flags' CHP plant, which commenced operations in June 2016, generated $3.9 million in additional gross margin.

Natural Gas Marketing

PESCO generated additional gross margin of $1.7 million for the six months ended June 30, 2017 compared to the same period in 2016. The increase in gross margin was generated primarily from providing natural gas to approximately 40,000 end users within one customer pool pursuant to the supplier agreement with Columbia Gas, as well as an increase in commercial and industrial customers served in Florida offset by lower gross margin in the Mid-Atlantic region. Under the supplier agreement, the timing of the deliveries of natural gas did not coincide with the payment of fixed storage and pipeline fees. PESCO delivered the highest volumes during the first quarter of 2017, while fixed storage and pipeline fees were paid over the entire twelve-month term of the agreement.

Pricing Amendments to Aspire Energy's Long-Term Agreements

An increase in gross margin of $844,000 was due to favorable pricing amendments to long-term sales agreements, which generated $1.4 million in gross margin, offset by the absence of a one-time management fee of $560,000 paid to Aspire Energy by CGC in the first quarter of 2016.

Customer Consumption - Weather and Other

Gross margin decreased by $836,000 as a result of lower sales of propane, due to warmer weather in 2017 compared to 2016, and decreased sales of natural gas by Aspire Energy due to warmer temperatures in Ohio.

Retail Propane Margins

Lower retail propane margins for our Delmarva and Florida propane distribution operations decreased gross margin by $305,000, of which $204,000 is associated with the larger Delmarva Peninsula propane distribution operation, as propane retail margins per gallon were slightly lower than 2016 levels.

Other Operating Expenses

Other operating expenses increased by $6.2 million. The significant components of the increase in other operating expenses included:

- $2.5 million incurred by Eight Flags' CHP plant, which commenced operations in June 2016;
- $935,000 in higher payroll costs for additional personnel to support growth;
- $809,000 in higher benefits and employee-related costs in 2017 (since we are self-insured, benefits costs will fluctuate depending upon actual claims experience);
- $609,000 in higher depreciation expense, of which $382,000 relates to a credit adjustment in 2016 recorded in conjunction with the final valuation for Aspire Energy;
- $514,000 in higher outside services costs associated primarily with growth and ongoing compliance activities; and
- $355,000 in higher operating expenses associated with the wind-down of Xeron’s operations.

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OTHER EXPENSE

For the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016

Other expense, which includes non-operating investment income (expense), interest income, late fees charged to customers and gains or losses from the sale of assets, increased by $599,000 for the second quarter of 2017 compared to the same period in 2016, due partly to costs associated with the termination of a lease for Xeron.

For the six months ended June 30, 2017 compared to the six months ended June 30, 2016

Other expense, which includes non-operating investment income (expense), interest income, late fees charged to customers and gains or losses from the sale of assets, increased by $842,000 for the first six months of 2017 compared to the same period in 2016, due partly to costs associated with the termination of a lease for Xeron.

INTEREST EXPENSE

For the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016

Interest charges for the three months ended June 30, 2017 increased by $449,000, compared to the same period in 2016, attributable to an increase of $325,000 in interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017 and an increase of $146,000 in interest on higher short-term borrowings.

For the six months ended June 30, 2017 compared to the six months ended June 30, 2016

Interest charges for the six months ended June 30, 2017 increased by $537,000, compared to the same period in 2016, attributable to an increase of $425,000 in interest on higher short-term borrowings and an increase of $208,000 on interest on long-term debt, largely as a result of the issuance of the Prudential Shelf Notes in April 2017.

INCOME TAXES

For the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016

Income tax expense was $3.9 million for the three months ended June 30, 2017, compared to $5.1 million in the same period in 2016. The decrease in income tax expense was due primarily to a decrease in our operating results. Our effective income tax rate was 39.5 percent and 38.8 percent, for the three months ended June 30, 2017 and 2016, respectively.

For the six months ended June 30, 2017 compared to the six months ended June 30, 2016

Income tax expense was $16.5 million for the six months ended June 30, 2017, compared to $18.4 million in the same period in 2016. The decrease in income tax expense was due primarily to a decrease in our operating results. Our effective income tax rate was 39.5 percent and 39.3 percent, for the six months ended June 30, 2017 and 2016, respectively.

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FINANCIAL POSITION, LIQUIDITY AND CAPITAL RESOURCES

Our capital requirements reflect the capital-intensive and seasonal nature of our business and are principally attributable to investment in new plant and equipment, retirement of outstanding debt and seasonal variability in working capital. We rely on cash generated from operations, short-term borrowings, and other sources to meet normal working capital requirements and to temporarily finance capital expenditures. We may also issue long-term debt and equity to fund capital expenditures and to more closely align our capital structure to our target capital structure.

Our energy businesses are weather-sensitive and seasonal. We normally generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas, electricity, and propane delivered by our natural gas, electric, and propane distribution operations and our natural gas gathering and processing operation to customers during the peak heating season. In addition, our natural gas and propane inventories, which usually peak in the fall months, are largely drawn down in the heating season and provide a source of cash as the inventory is used to satisfy winter sales demand.

Capital expenditures for investments in new or acquired plant and equipment are our largest capital requirements. Our capital expenditures were $82.7 million for the six months ended June 30, 2017.

We originally budgeted $260.3 million for capital expenditures during 2017, and we currently project capital expenditures of approximately $208.0 million in 2017. Our current forecast by segment and by business line is shown below:

	2017
(dollars in thousands)	
Regulated Energy:	
Natural gas distribution	$68,645
Natural gas transmission	105,147
Electric distribution	11,751
Total Regulated Energy	185,543
Unregulated Energy:	
Propane distribution	10,451
Other unregulated energy	5,955
Total Unregulated Energy	16,406
Other:	
Corporate and other businesses	6,002
Total Other	6,002
Total 2017 Capital Expenditures	$207,951

The capital expenditure projection is subject to continuous review and modification. Actual capital requirements may vary from the above estimates due to a number of factors, including changing economic conditions, customer growth in existing areas, regulation, new growth or acquisition opportunities and availability of capital. Historically, actual capital expenditures have typically lagged behind the budgeted amounts.

The timing of capital expenditures can vary based on delays in regulatory approvals, securing environmental approvals and other permits. The regulatory application and approval process has lengthened in the past few years, and we expect this trend to continue.

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Capital Structure
We are committed to maintaining a sound capital structure and strong credit ratings to provide the financial flexibility needed to access capital markets when required. This commitment, along with adequate and timely rate relief for our regulated energy operations, is intended to ensure our ability to attract capital from outside sources at a reasonable cost. We believe that the achievement of these objectives will provide benefits to our customers, creditors and investors.
The following table presents our capitalization, excluding and including short-term borrowings, as of June 30, 2017 and December 31, 2016:

	June 30, 2017		December 31, 2016	
(in thousands)				
Long-term debt, net of current maturities	$201,590	30 %	$136,954	23 %
Stockholders' equity	461,678	70 %	446,086	77 %
Total capitalization, excluding short-term debt	$663,268	100%	$583,040	100%

	June 30, 2017		December 31, 2016	
(in thousands)				
Short-term debt	$145,591	18 %	$209,871	26 %
Long-term debt, including current maturities	213,714	26 %	149,053	19 %
Stockholders' equity	461,678	56 %	446,086	55 %
Total capitalization, including short-term debt	$820,983	100%	$805,010	100%

Included in the long-term debt balances at June 30, 2017 and December 31, 2016, was a capital lease obligation associated with Sandpiper's capacity, supply and operating agreement ($1.4 million excluding current maturities and $2.8 million including current maturities, and $2.1 million excluding current maturities and $3.5 million, including current maturities, respectively). At the closing of the ESG acquisition in May 2013, Sandpiper entered into this agreement, which has a six-year term. The capacity portion of this agreement is accounted for as a capital lease.
Our target ratio of equity to total capitalization, including short-term borrowings, is between 50 and 60 percent. We have maintained a ratio of equity to total capitalization, including short-term borrowings, between 50 percent and 57 percent during the past three years. In September 2016, we completed a public offering of 960,488 shares of our common stock at a price per share of $62.26. The net proceeds from the sale of common stock, after deducting underwriting commissions and expenses, were approximately $57.4 million, which were added to our general funds and used primarily to repay a portion of our short-term debt under unsecured lines of credit.
As described below under "Short-term Borrowings," we entered into the Credit Agreement and the Revolver with the Lenders in October 2015, which increased our borrowing capacity by $150.0 million. To facilitate the refinancing of a portion of the short-term borrowings into long-term debt, as appropriate, we also entered into the Prudential Shelf Agreement with Prudential for the potential private placement of the Prudential Shelf Notes as further described below under the heading "Shelf Agreements." In addition, we also entered into the MetLife and NYL Shelf Agreements, as described in further detail below, to have additional debt capital available to fund future growth capital expenditures.
We will seek to align, as much as feasible, any long-term debt or equity issuance(s) with the commencement of service, and associated earnings, for larger revenue generating capital projects. In addition, the exact timing of any long-term debt or equity issuance(s) will be based on market conditions.
Shelf Agreements
In October 2015, we entered into the Prudential Shelf Agreement, under which, through October 8, 2018, we may request that Prudential purchase up to $150.0 million of our Prudential Shelf Notes. The Prudential Shelf Notes have a fixed interest rate and a maturity date not to exceed 20 years from the date of issuance. Prudential is under no obligation to purchase any of the Prudential Shelf Notes. The interest rate and terms of payment of any series of the

Prudential Shelf Notes will be determined at the time of purchase.

In May 2016, Prudential confirmed and accepted our request that Prudential purchase $70.0 million of 3.25 percent Prudential Shelf Notes under the Prudential Shelf Agreement. We issued the Prudential Shelf Notes on April 21, 2017 and used the proceeds to reduce short-term borrowings under the Revolver, which had increased as a result of funding capital expenditures on a temporary basis.

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The Prudential Shelf Agreement sets forth certain business covenants to which we are subject when any Prudential Shelf Note is outstanding, including covenants that limit or restrict our ability, and the ability of our subsidiaries, to incur indebtedness, or place or permit liens and encumbrances on any of our property or the property of our subsidiaries.

In March 2017, we entered into the MetLife Shelf Agreement and NYL Shelf Agreement, under which, through March 2, 2020, we may request that MetLife and NYL purchase up to $150.0 million and $100 million, respectively, of our unsecured senior debt at a fixed interest rate and with a maturity date not to exceed 20 years from the date of issuance. MetLife and NYL are under no obligation to purchase any unsecured senior debt. The interest rate and terms of payment of any series of unsecured senior debt will be determined at the time of purchase. As of June 30, 2017, no notes have been issued under either the MetLife Shelf Agreement or the NYL Shelf Agreement.

Short-term Borrowings

Our outstanding short-term borrowings at June 30, 2017 and December 31, 2016 were $145.6 million and $209.9 million, respectively. The weighted average interest rates for our short-term borrowings were 1.87 percent and 1.37 percent, for the six months ended June 30, 2017 and 2016, respectively.

We utilize bank lines of credit to provide funds for our short-term cash needs to meet seasonal working capital requirements and to temporarily fund portions of the capital expenditure program. As of June 30, 2017, we had four unsecured bank credit facilities with three financial institutions totaling $180.0 million in total available credit.

In addition, since October 2015, we have $150.0 million of additional short-term debt capacity available under the Revolver with five participating Lenders. The $150.0 million Revolver has a five-year term and is subject to the terms and conditions set forth in the Credit Agreement. Borrowings under the Revolver will be used for general corporate purposes, including repayments of short-term borrowings, working capital requirements and capital expenditures. Borrowings under the Revolver will bear interest at: (i) the LIBOR Rate plus an applicable margin of 1.25 percent or less, with such margin based on total indebtedness as a percentage of total capitalization, both as defined by the Credit Agreement, or (ii) the base rate plus 0.25% or less. Interest is payable quarterly, and the Revolver is subject to a commitment fee on the unused portion of the facility. We have the right, under certain circumstances, to extend the expiration date for up to two years on any anniversary date of the Revolver, with such extension subject to the Lenders' approval. We may also request the Lenders to increase the Revolver to $200.0 million, with any increase at the sole discretion of each Lender.

None of the unsecured bank lines of credit requires compensating balances. We are currently authorized by our Board of Directors to incur up to $275.0 million of short-term borrowing.

Cash Flows

The following table provides a summary of our operating, investing and financing cash flows for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
	2017	2016
(in thousands)		
Net cash provided by (used in):		
Operating activities	$96,370	$77,663
Investing activities	(88,577)	(72,871)
Financing activities	(9,552)	(4,381)
Net (decrease) increase in cash and cash equivalents	(1,759)	411
Cash and cash equivalents—beginning of period	4,178	2,855
Cash and cash equivalents—end of period	$2,419	$3,266

Cash Flows Provided By Operating Activities

Changes in our cash flows from operating activities are attributable primarily to changes in net income, adjusted for non-cash items such changes in deferred income taxes, depreciation and working capital. Changes in working capital are determined by a variety of factors, including weather, the prices of natural gas, electricity and propane, the timing of customer collections, payments for purchases of natural gas, electricity and propane, and deferred fuel cost recoveries.

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During the six months ended June 30, 2017 and 2016, net cash provided by operating activities was $96.4 million and $77.7 million, respectively, resulting in an increase in cash flows of $18.7 million. Significant operating activities generating the cash flows change were as follows:

- Changes in net accounts receivable and accrued revenue and accounts payable and accrued liabilities increased cash flows by $24.9 million, due primarily to higher revenues and the timing of the receipt of customer payments as well as the timing of payments to vendors.
- Changes in income taxes decreased cash flows by $12.2 million, due to lower pre-tax income and lower tax refund during the first six months of 2017 compared to the same period in 2016.
- Net income, adjusted for reconciling activities, increased cash flows by $7.1 million, due primarily to an increase in deferred income taxes as a result of the availability and utilization of bonus depreciation in the first six months of 2017, which resulted in a higher book-to-tax timing difference and higher non-cash adjustments for depreciation and amortization related to increased investing activities.
- Changes in net regulatory assets and liabilities increased cash flows by $3.7 million, due primarily to changes in fuel costs collected through the various fuel cost recovery mechanisms.
- Net cash flows from changes in other inventories decreased by approximately $3.2 million, due primarily to additional pipes and other construction inventory purchases which increased the levels of our inventory.
- Changes in net customer deposits and refunds, prepaid expenses and other current assets, accrued compensation and other assets and liabilities decreased cash flows by $1.6 million.

Cash Flows Used in Investing Activities

Net cash used in investing activities totaled $88.6 million and $72.9 million during the six months ended June 30, 2017 and 2016, respectively, resulting in a decrease in cash flows of $15.7 million. The decrease was due primarily to an increase in cash used for capital expenditures.

Cash Flows Used in Financing Activities

Net cash used in financing activities totaled $9.6 million and $4.4 million during the six months ended June 30, 2017 and 2016, respectively. The increase in net cash used in financing activities for the six months ended June 30, 2017 resulted primarily from the following:

- We received $69.8 million in net cash proceeds from the issuance of the Prudential Shelf Notes, and we paid $2.9 million in scheduled long-term debt principal payments and capital lease obligations payments.
- Net repayments of $67.1 million under our line of credit arrangements. The proceeds from the long-term debt issuance of the Prudential Shelf Notes were used to repay borrowings under our lines of credit. Change in cash overdrafts decreased cash flows by $3.8 million.
- We paid $9.6 million in cash dividends for the six months ended June 30, 2017, compared to $8.5 million for the six months ended June 30, 2016.

Off-Balance Sheet Arrangements

We have issued corporate guarantees to certain vendors of our subsidiaries, primarily PESCO. These corporate guarantees provide for the payment of natural gas purchases in the event of default. PESCO has never defaulted on its obligations to pay its suppliers. The liabilities for these purchases are recorded in our financial statements when incurred. The aggregate amount guaranteed at June 30, 2017 was $57.2 million, with the guarantees expiring on various dates through June 2018.

We have issued letters of credit totaling $5.8 million related to the electric transmission services for FPU's northwest electric division, the firm transportation service agreement between TETLP and our Delaware and Maryland divisions, and to our current and previous primary insurance carriers. These letters of credit have various expiration dates through June 2018. There have been no draws on these letters of credit as of June 30, 2017. We do not anticipate that the letters of credit will be drawn upon by the counterparties, and we expect that they will be renewed to the extent necessary in the future. Additional information is presented in Note 5, Other Commitments and Contingencies in the condensed consolidated financial statements.

Contractual Obligations

There has been no material change in the contractual obligations presented in our 2016 Annual Report on Form 10-K, except for long-term debt, commodity purchase obligations and forward contracts entered into in the ordinary course of our business. The following table summarizes long-term debt, commodity and forward contract obligations at June 30, 2017:

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	Payments Due by Period				
	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
(in thousands)					
Long-term debt	$10,698	$ 24,226	$ 37,200	$ 139,300	$211,424
Purchase obligations - Commodity [1]	44,380	1,696	—	—	46,076
Total	$55,078	$ 25,922	$ 37,200	$ 139,300	$257,500

[1] In addition to the obligations noted above, we have agreements with commodity suppliers that have provisions with no minimum purchase requirements. There are no monetary penalties for reducing the amounts purchased; however, the propane contracts allow the suppliers to reduce the amounts available in the winter season if we do not purchase specified amounts during the summer season. Under these contracts, the commodity prices will fluctuate as market prices fluctuate.

Rates and Regulatory Matters

Our natural gas distribution operations in Delaware, Maryland and Florida and electric distribution operation in Florida are subject to regulation by the respective state PSC; Eastern Shore is subject to regulation by the FERC; and Peninsula Pipeline is subject to regulation by the Florida PSC. At June 30, 2017, we were involved in regulatory matters in each of the jurisdictions in which we operate. Our significant regulatory matters are fully described in Note 3, Rates and Other Regulatory Activities, to the condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Recent Authoritative Pronouncements on Financial Reporting and Accounting

Recent accounting developments applicable to us and their impact on our financial position, results of operations and cash flows are described in Note 1, Summary of Accounting Policies, to the condensed consolidated financial statements in this Quarterly Report on Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

INTEREST RATE RISK

Long-term debt is subject to potential losses based on changes in interest rates. Our long-term debt at June 30, 2017, consists of fixed-rate Senior Notes and $8.0 million of fixed-rate secured debt. We evaluate whether to refinance existing debt or permanently refinance existing short-term borrowings based in part on the fluctuation in interest rates. Additional information about our long-term debt is disclosed in Note 13, Long-term Debt, in the condensed consolidated financial statements.

COMMODITY PRICE RISK

Regulated Energy Segment

We have entered into agreements with various wholesale suppliers to purchase natural gas and electricity for resale to our customers. Our regulated energy distribution businesses that sell natural gas or electricity to end-use customers have fuel cost recovery mechanisms authorized by the PSCs that allow us to periodically adjust fuel rates to reflect changes in the wholesale cost of natural gas and electricity and to ensure that we recover all of the costs prudently incurred in purchasing natural gas and electricity for our customers. Therefore, our regulated energy distribution operations have limited commodity price risk exposure.

Unregulated Energy Segment

Sharp and Flo-gas are exposed to commodity price risk as a result of the competitive nature of retail pricing offered to our customers. In order to mitigate this risk, we utilize propane storage activities and forward contracts for supply. We can store up to approximately 6.2 million gallons of propane (including leased storage and rail cars) during the winter season to meet our customers' peak requirements and to serve metered customers. Decreases in the wholesale price of propane may cause the value of stored propane to decline, particularly if we utilize fixed price forward contracts for supply. To mitigate the risk of propane commodity price fluctuations on the inventory valuation, we have adopted a Risk Management Policy that allows our propane distribution operation to enter into fair value hedges, cash flows hedges or other economic hedges of our inventory.

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Aspire Energy is exposed to commodity price risk, primarily during the winter season, to the extent we are not successful in balancing our natural gas purchases and sales and have to secure natural gas from alternative sources at higher spot prices. In order to mitigate this risk, we procure firm capacity that meets our estimated volume requirements and we continue to seek out new producers with which to contract in order to fulfill our natural gas purchase requirements.

PESCO is a party to natural gas futures contracts. These contracts provide PESCO with the right to purchase natural gas at a fixed price at future dates. Upon expiration, the contracts can be settled financially without taking delivery of natural gas, or PESCO can procure natural gas for its customers.

PESCO is subject to commodity price risk on its open positions to the extent that market prices for natural gas liquids and natural gas deviate from fixed contract settlement prices. Market risk associated with the trading of futures and forward contracts is monitored daily for compliance with our Risk Management Policy, which includes volumetric limits for open positions. To manage exposures to changing market prices, open positions are marked up or down to market prices and reviewed daily by our oversight officials. In addition, the Risk Management Committee reviews periodic reports on markets, approves any exceptions to the Risk Management Policy (within limits established by the Board of Directors) and authorizes the use of any new types of contracts.

WHOLESALE CREDIT RISK

The Risk Management Committee reviews credit risks associated with counterparties to commodity derivative contracts prior to such contracts being approved.

Additional information about our derivative instruments is disclosed in Note 11, Derivative Instruments, in the condensed consolidated financial statements.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer of Chesapeake Utilities, with the participation of other Company officials, have evaluated our “disclosure controls and procedures” (as such term is defined under Rules 13a-15(e) and 15d-15(e), promulgated under the Securities Exchange Act of 1934, as amended) as of June 30, 2017. Based upon their evaluation, the Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2017.

Changes in Internal Control over Financial Reporting

During the quarter ended June 30, 2017, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II—OTHER INFORMATION

Item 1. Legal Proceedings

As disclosed in Note 5, Other Commitments and Contingencies, of the condensed consolidated financial statements in this Quarterly Report on Form 10-Q, we are involved in certain legal actions and claims arising in the normal course of business. We are also involved in certain legal and administrative proceedings before various governmental or regulatory agencies concerning rates and other regulatory actions. In the opinion of management, the ultimate disposition of these proceedings and claims will not have a material effect on our condensed consolidated financial position, results of operations or cash flows.

Item 1A. Risk Factors

Our business, operations, and financial condition are subject to various risks and uncertainties. The risk factors described in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K, for the year ended December 31, 2016, should be carefully considered, together with the other information contained or incorporated by reference in this Quarterly Report on Form 10-Q and in our other filings with the SEC in connection with evaluating Chesapeake Utilities, our business and the forward-looking statements contained in this Quarterly Report on Form 10-Q. Additional risks and uncertainties not known to us at present, or that we currently deem immaterial, also may affect Chesapeake Utilities. The occurrence of any of these known or unknown risks could have a material adverse impact on our business, financial condition and results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs [2]	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs [2]
April 1, 2017 through April 30, 2017 [1]	379	$ 69.80	—	—
May 1, 2017 through May 31, 2017	—	$ —	—	—
June 1, 2017 through June 30, 2017	—	$ —	—	—
Total	379	$ 69.80	—	—

(1) Chesapeake Utilities purchased shares of stock on the open market for the purpose of reinvesting the dividend on deferred stock units held in the Rabbi Trust accounts for certain Directors and Senior Executives under the Deferred Compensation Plan. The Deferred Compensation Plan is discussed in detail in Item 8 under the heading "Notes to the Consolidated Financial Statements—Note 16, Employee Benefit Plans" in our latest Annual Report on Form 10-K for the year ended December 31, 2016. During the quarter ended June 30, 2017, 379 shares were purchased through the reinvestment of dividends on deferred stock units.

(2) Except for the purposes described in Footnote [1], Chesapeake Utilities has no publicly announced plans or programs to repurchase its shares.

Item 3. Defaults upon Senior Securities

None.

Item 5. Other Information

None.

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Item 6. Exhibits

10.1	Form of Performance Share Agreement, effective February 23, 2017 for the period 2017 to 2019, pursuant to Chesapeake Utilities Corporation 2013 Stock and Incentive Compensation Plan by and between Chesapeake Utilities Corporation and each of Michael P. McMasters, Beth W. Cooper, Stephen C. Thompson, Elaine B. Bittner, Jeffry M. Householder and James F. Moriarty is filed herewith.
31.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
31.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934.
32.1	Certificate of Chief Executive Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
32.2	Certificate of Chief Financial Officer of Chesapeake Utilities Corporation pursuant to 18 U.S.C. Section 1350.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

Replaces Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended March 31, 2017 in order to correct an inadvertent scrivener's error as to the grant date in the previously filed version.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CHESAPEAKE UTILITIES CORPORATION

/S/ BETH W. COOPER
Beth W. Cooper
Senior Vice President and Chief Financial Officer
Date: August 3, 2017